Nova Scotia Utility and Review Board

IN THE MATTER OF The Public Utilities Act, R.S.N.S. 1989, c.380, as amended

\- and -

IN THE MATTER OF A PROCEEDING Concerning Sales of Renewable Low Impact Electricity Generated within Nova Scotia by a Retail Seller to a Retail Customer pursuant to the Electricity Act (M06214)

NS Power

Renewable to Retail

Application

September 1, 2015

NON-CONFIDENTIAL

TABLE OF CONTENTS

LIST OF APPENDICES

- Presentation: Rate Setting at NS Power
- Presentation: Background OATT and GIP information

Appendix 9 Materials from March 2, 2015 Stakeholder consultation

- Presentation: Robert Cary RtR Design Basis Development
- Presentation: NS Power Renewable to Retail Work Plan and Schedule
- Stakeholder Comments on March 2 Conference

Appendix 10 Draft Board Electricity Retailers Regulations and Code of Conduct, issued July 15, 2015

Appendix 11 Materials circulated to Stakeholders on May 21, 2015

- NS Power LRS Terms and Conditions and LRS Participation Agreement
- NS Power Distribution Tariff Rate Strawman Report
- NS Power Distribution Tariff and Attachments A, B, D, E
- NS Power Distribution Tariff Attachment C (ELECTRONIC)

Appendix 12 Materials circulated to Stakeholders on June 11, 2015

- Draft Energy Balancing Service Tariff
- Draft Standby Service Tariff
- Draft Schedule 4A from OATT
- Presentation: BUTUS redesign for Renewable to Retail

Appendix 13 Stakeholder Data Requests and NS Power responses

Appendix 13A CA DR-04 Att 2 ELECTRONIC

Appendix 13B Multeese DR-25 Att 1 ELECTRONIC

Appendix 13C Multeese DR-29 Att 1 ELECTRONIC

Appendix 13D Multeese DR-31 Att 1 ELECTRONIC

Appendix 13E SWFI DR-01 Att 1 ELECTRONIC

Appendix 13F SWFI DR-02 Att 1 ELECTRONIC

Appendix 14 July 22, 2015 Stakeholder Teleconference

Summary and Updated SWFI DR-01 Att 1 in PDF

Appendix 14A	Updated SWFI DR-01 Att 1 ELECTRONIC
Appendix 15	Materials circulated to Stakeholders on July 23, 2015 • Presentation: Draft Renewable to Retail Market Transition Tariff (dated July 22, 2105) • Draft Renewable to Retail Market Transition Tariff
Appendix 16	Robert Cary & Associates Inc. RtR Design Basis Report
Appendix 17	Distribution Tariff
Appendix 17A	Distribution Tariff Rates Calculation ELECTRONIC
Appendix 18	LRS Terms and Conditions and LRS Participation Agreement
Appendix 19	Energy Balancing Service Tariff (EBS)
Appendix 19A	EBS Tariff Charge calculations ELECTRONIC
Appendix 20	Standby Service Tariff (SS)
Appendix 21	Amended 2014 OATT Schedule 4 and proposed new OATT Schedule 4A
Appendix 22	OATT with proposed amendments
Appendix 23	Renewable to Retail Market Transition Tariff (RTT)
Appendix 24	Tariff Calculation Workbook ELECTRONIC
Appendix 25	Nova Scotia Wholesale Electricity Market Rules with proposed amendments
Appendix 26	NS Power Regulations with proposed amendments
Appendix 27	Generator Interconnection Procedures (GIP) with proposed amendments
Appendix 28	Standard Generator Interconnection and Operating Agreement (GIA) with proposed amendments

FREQUENTLY USED ABBREVIATIONS

Cary Report	RtR Design Basis Report by Robert Cary & Associates Inc.
COS	Cost of Service
COSS	Cost of Service Study
DT	Distribution Tariff
EBS	Renewable to Retail Market Energy Balancing Service Tariff
ECR	Embedded Cost Recovery
GIP	Generator Interconnection Procedures
LRS	Licenced Retail Supplier
OATT	Open Access Transmission Tariff
Retailers Regulations	Board Electricity Retailers Regulations
RtR	Renewable to Retail
RTT	Renewable to Retail Market Transition Tariff
SS	Renewable to Retail Market Standby Service

1.0 EXECUTIVE SUMMARY

This Application proposes a comprehensive regulatory framework to enable the purchase by retail customers[1] (Retail Customers) of renewable low-impact electricity[2] generated in Nova Scotia from Licenced Retail Suppliers (LRS), who are retail suppliers licenced by the Nova Scotia Utility and Review Board (Board or UARB) in accordance with the *Electricity Act*, S.N.S. 2004, c. 25. The tariffs and procedures described in this Application have been developed over the past several months in consultation with stakeholders and are presented herein for the Board review and approval.

Within this application, Nova Scotia Power Inc. (NS Power or Company) requests approval of:

1. The Distribution Tariff as set out in **Appendix 17**;

2. The LRS Participation Agreement and the LRS Terms and Conditions, as set out in **Appendix 18,** subject to the qualifications and provisions noted herein;

3. The Energy Balancing Service Tariff as set out in **Appendix 19**;

4. The Standby Service Tariff as set out in **Appendix 20;**

5. Amendments to 2014 OATT Schedule 4 and a new OATT Schedule 4A, both as set out in **Appendix 21**;

6. The proposed amendments to the OATT as set out in **Appendix 22**;

[1] NS Power uses the term Retail Customer to describe an individually metered facility (i.e. an account).
[2] The definition of renewable low-impact electricity is provided in the Nova Scotia Renewable Electricity Standard, https://www.novascotia.ca/just/regulations/regs/elecrenew.htm#TOC2_2

7. The Renewable to Retail Market Transition Tariff as set out in **Appendix 23**;

8. The amendments to the NS Power Regulations as set out **Appendix 26**;

9. The amendments to the Generator Interconnection Procedures as set out in **Appendix 27** including the amendments to the Standard Generator Interconnection and Operating Agreement as set out in **Appendix 28**.

NS Power is also proposing amendments to the Wholesale Electricity Market Rules as set out in **Appendix 25** which will require adoption by the Nova Scotia Power System Operator. NS Power submits these amendments to the Board for review for the purposes of ensuring the amendments proposed will align with the approved RtR design framework.

Development of these elements of the new "Renewable to Retail" (RtR) market has been guided by the legislative framework enacted by the Province of Nova Scotia for the RtR market as well as established regulatory practice within Nova Scotia. The tariffs presented are cost-based and provide an appropriate level of flexibility as the Company gains experience with the growth and scope of RtR market.

Consistent with the fundamental premise of the enabling legislation, the tariffs provide for recovery of the cost of introducing this service from the Retail Customers and Licenced Retail Suppliers that engage in the market without negatively affecting (i.e. cost transfer) NS Power customers taking service under bundled utility tariffs or other participants in the Nova Scotia electricity market. As such, the design of this market opening and the participation in it by suppliers and customers must not create additional cost burden for remaining/non-RtR Customers.

NS Power looks forward to continued engagement with stakeholders throughout the regulatory proceeding which will follow submission of this Application. The Company recognizes that given this initiative represents the creation of a new electricity market in Nova Scotia, opportunities to refine or further develop elements of the Application may be identified during this proceeding. It is the Company's objective to engage actively in the stakeholder review that follows and seek opportunities to promote consensus on as many matters as possible in advance of the UARB hearing scheduled for January 2016.

2.0 INTRODUCTION

The *Electricity Reform Act*, S.N.S. 2013, c. 34, amended the *Electricity Act*, S.N.S. 2004, c. 25[3] (Act) to enable the purchase of renewable low-impact electricity generated in Nova Scotia by Retail Customers (as defined in the Act). Section 3C of the Act provides as follows:

> **Retail customers and renewable low-impact electricity**
>
> **3C** **(1)** Effective on the date prescribed in the regulations,
>
> (a) a retail supplier who meets the requirements in Section 3D may sell to a retail customer; and
>
> (b) a retail customer, other than a customer of a municipal utility, may purchase from such a retail supplier, renewable low-impact electricity generated within the Province.
>
> **(2)** Nova Scotia Power Incorporated shall not refuse to provide service to a retail customer on the basis that the customer purchases renewable low-impact electricity from a retail supplier.
>
> **(3)** The Board has all the power and authority necessary to implement this Section. 2013, c. 34, s. 3.

The Act also sets the essential framework for this market opening. Section 3G of the Act provides as follows:

> **Nova Scotia Power Incorporated obligations**
>
> **3G (1)** Notwithstanding Section 77 of the *Public Utilities Act*, on or before the applicable date prescribed by the regulations, Nova Scotia Power Incorporated shall develop in consultation with stakeholders, and file with the Board for approval, any tariffs,

[3] The Electricity Act is provided as Appendix 1.

procedures and standards of conduct and any amendments to existing tariffs, procedures and standards of conduct that are necessary to facilitate the purchase of renewable low-impact electricity as provided for in Section 3C, including

(a) a new or amended open access transmission tariff;
(b) a distribution tariff;
(c) a new or amended backup/top-up service tariff;
(d) a new or amended non-dispatchable supplier spill tariff;
(e) new or amended interconnection procedures;
(f) new or amended market rules; and
(g) any other tariffs, procedures or standards of conduct prescribed by the regulations or that the Board requires Nova Scotia Power Incorporated to develop or amend in order to facilitate the purchase of renewable low-impact electricity as provided for in Section 3C.

(2) In reviewing and approving the tariffs, procedures and standards of conduct required to be developed or amended pursuant to this Section, the Board shall be guided by the following principles:

(a) **customers of Nova Scotia Power Incorporated** and persons who, at the coming into force of this Section, are independent power producers or hold feed-in tariff approvals within the meaning of the regulations **are not to be negatively affected if some retail customers choose to purchase renewable low-impact electricity from a retail supplier**;

(b) **retail suppliers and their customers are to be responsible for all costs related to the provision of service by retail suppliers to their customers** that would otherwise be the responsibility of Nova Scotia Power Incorporated and its customers. 2013, c. 34, s. 3.

[**emphasis added**]

2.1 Terms of Reference

At the first meeting with stakeholders in June 2014, NS Power presented the draft Terms of Reference for this project. The Terms of Reference set out the scope, objective, approach, consultation framework, criteria, and timeline for the project. The initial draft

Terms of Reference, Stakeholder comments, and the final Terms of Reference of July 11, 2014 are attached as **Appendix 3**.

2.2 Principles

The following principles applicable to this Application are based on the framework set out in the Act:

1. NS Power is responsible for developing and administering the tariffs and procedures necessary to enable retail competition for renewable low-impact electricity produced in Nova Scotia;

2. Regulation of NS Power's provision of services enabling the opening of the RtR market and the associated tariffs and procedures is the responsibility of the Board;

3. NS Power's development of these tariffs and procedures and the Board's approval of same must ensure NS Power's customers and independent power producers or holders of feed-in tariff approvals are not negatively affected if Retail Customers choose to purchase renewable low-impact electricity from a LRS;

4. Costs arising from the introduction of this market opening must be borne solely by the LRS and its customers and not NS Power and its remaining customers;

5. NS Power maintains its obligation to provide service in the event a Retail Customer elects to take service from an LRS and in the event the customer returns to NS Power to take service under the Company's bundled service rates.[4]

[4] Bundled service refers to electrical service taken from NS Power under existing NS Power tariffs approved by the Board. This takes the form of having generation, transmission, distribution, ancillary services and all other items associated with the provision of such service blended or bundled within the rate.

6. The pace and magnitude of the RtR market opening, its effect on NS Power's cost structure and support systems in the near and longer-term remains to be determined.

As a result of this legislative construct and the uncertain pace and scope of the RtR market opening in Nova Scotia, NS Power adopted the following approach in the development of the RtR market tariffs and procedures:

1. The tariffs should reflect established regulatory rate-making practices;

2. The tariffs must operate so as to avoid any transfer of cost responsibility from customers opting for RtR supply to those customers continuing to take bundled service from NS Power. This means that the tariffs must provide for full recovery of: (a) the direct cost of providing service to the RtR market; (b) costs incurred by NS Power to date to service these customers; and (c) costs which the Company will continue to incur in order to remain ready to provide service to this customer group in the event they return to NS Power's bundled service in the future;

3. The Company should leverage existing processes and tools to minimize the cost of this market opening for licenced Retailer Suppliers and Retail Customers; and

4. Refinements to the processes and models will likely be required as experience with the RtR market opening is gained and confidence increased due to a better understanding of the pace, scope and requirements of this market.

2.3 Development Process

Within this Application, NS Power submits changes to the OATT; a new Distribution Tariff; revisions to the NS Power Regulations, new Energy Balancing and Standby Service Tariffs that provide for backup, top-up and spill services; a new RtR Market

Transition Tariff to recover embedded costs from LRSs; amendments to the Generation Interconnection Procedures; amendments to the current Wholesale Electricity Market Rules; and a LRS Participation Agreement which establish collectively the relationship between an LRS and NS Power and sets out the various procedures and terms and conditions applicable to an LRS for the purpose of enabling the supply of renewable low-impact electricity to a Retail Customer through the incorporation of the LRS Terms and Conditions.

This Application reflects the work of the Company and input gathered from stakeholders to date during the stakeholder consultation process. Development of this submission has been a significant undertaking and has benefitted from the engagement of all parties, including customer representatives and potential generators and LRS. Throughout this process, NS Power has sought to be collaborative, flexible and transparent. The Application provides a complete record of the engagement to date. Stakeholder engagement is summarized in Section 3. All project documents issued to stakeholders or received from stakeholders in this process were published to the NS Power public website,[5] and are attached as Appendices 2 through 15 to this Application.

The Company was assisted in the development of the market design by Robert Cary. Mr. Cary is a consultant experienced in electricity market restructuring. He was a consultant to the Province of Nova Scotia on the Electricity Market Governance Committee work, which laid the foundation of the Wholesale Electricity Market opening; previously represented the Province in the development of the Nova Scotia Wholesale Electricity Market Rules applicable to the wholesale market opening; and advised NS Power on tariff design and related issues. Mr. Cary has also consulted extensively in the Ontario Wholesale Electricity Market and the New Brunswick electricity market. Mr. Cary's full qualifications and experience are included in his Design Basis Report (referred to herein as the Cary Report) which is attached as **Appendix 16.**

[5] Stakeholder consultation documents were published on http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/regulatory-initiatives/renewable-to-retail.aspx.

Mr. Cary was engaged by NS Power in September 2014, and has delivered three key design papers: the Market Design White Paper,[6] the Embedded Cost Recovery White Paper,[7] and the Cary Report[8] upon which the development of this project is based. Mr. Cary attended all the stakeholder conferences and presented and answered questions, in addition to providing advice and document review to NS Power throughout this project.

In general, the Cary Report provides a broader discussion of matters considered in the selection of alternative approaches to market design elements and expands on the analysis underlying certain matters. With certain exceptions, these discussions are not repeated in the body of this Application. The Cary Report also provides an overview of the tariffs, procedures and agreements proposed by NS Power for the RtR market as well as amendments to existing tariffs, regulations and rules required for the implementation of the RtR framework.

As previously noted, further refinements to these tariffs, procedures and processes may be required as the RtR market framework is further refined during this proceeding. The documents have been prepared based on certain assumptions by the Company as set out in Section 6 below.

The regulatory proceeding schedule was issued by the Board on July 15, 2015.[9] It provides for an initial technical conference on this matter as well as further discovery by Intervenors and settlement discussions prior to the oral hearing in January 2016. NS Power remains committed to collaborating with all parties throughout the remainder of 2015 with the objective of producing an RtR market framework which complies with the

[6] The Market Design White Paper is provided in Appendix 6, pages 41-70
[7] The Embedded Cost Recovery White Paper is provided in Appendix 7, pages 1-28.
[8] The RtR Design Basis Document Report is provided in Appendix 16.
[9] UARB documents in this matter can be found at http://uarb.novascotia.ca/ under Case Number M06214.

legislative provisions enacted by the Province; is aligned with the regulatory processes established by the Board; and best serves the interests of NS Power customers.

NS Power recognizes that further refinements may be necessary as implementation proceeds and the nature and size of the market emerge.

Finally, the Company notes that tariffs, procedures and processes proposed in this Application are for the purposes of the development of this RtR market only. They are responsive to the requirements of the Act and should not be interpreted as setting a precedent for the Company in any regard other than for the creation of this RtR market.

2.4 Compliance Filing

The proposed tariffs set out in this Application may be impacted by subsequent regulatory proceedings filed by the Company or by further refinements to design framework made during this proceeding. Upon approval of the design framework and the tariffs, NS Power anticipates the requirement for a Compliance Filing to the Board for approval to account for any necessary revisions to the tariffs, the LRS Terms and Conditions, the LRS Participation Agreement, or the proposed amendments to the NS Power Regulations, the OATT, the Market Rules or the Generator Interconnection Procedures, as well the completion or finalization of any of the outstanding matters set out in Section 12 herein.

In addition to the revisions incorporated within the anticipated Compliance filing, the Company proposes that the rates in the RtR tariffs be adjusted annually within the Annually Adjusted Rates framework based on forecast fuel costs for the following year.

3.0 STAKEHOLDER CONSULTATION

On April 30, 2014, NS Power wrote to the Board to request that a proceeding be opened and Notice be provided to interested parties to facilitate the Company's stakeholder consultation on the development of the RtR market framework. On May 2, 2014, the Board issued an Order[10] directing NS Power to initiate the consultation process and publish a Notice of Hearing, which provided that interested parties should notify the Board of their intention to participate in this activity by May 30, 2014.

Since that time, the Board has created and maintained the Participants List.[11] During the stakeholder consultation phase, the list comprised NS Power, Board staff and counsel, the Consumer Advocate (CA), the Small Business Advocate (SBA), The Industrial Group (IG), Port Hawkesbury Paper (PHP), the Nova Scotia Department of Energy (DOE) and the following persons and organizations: Alternative Resource Energy Authority, Auley Carey, Bullfrog Power, Cape Breton Explorations, Celtic Current, Crannog Developments, Dalhousie University, Endurance Wind Power, Enercon Canada, Fundy Tidal, George LeBlanc Consulting, Highland Energy (NS), Lahave Renewables, Lighthouse Route Energy Ventures, Minas Energy, Natural Forces, Paul Lewis, Redcamp Services, Scotian WindFields, and Watts Wind. NS Power used this list to communicate with stakeholders.

3.1 Stakeholder Consultation Process

Between June 2014 and August 2015, NS Power engaged in a process of seeking discussion and opinions from stakeholders, with the purpose of obtaining their input into the design of the tariffs and market documentation, and to discover points of consensus. NS Power hosted five stakeholder consultation conferences in person with simultaneous teleconferencing over WebEx, and exchanged proposed tariffs, papers, presentations and

[10] NS Power's letter and the Notice of Proceeding can be found in Appendix 2.
[11] M06214, Renewable to Retail, Participants List.

Data Requests with stakeholders. All written materials were emailed to stakeholders and posted on www.nspower.ca,[12] and are provided as **Appendices 3 to 15** to this Application.

NS Power appreciates the input of the many stakeholders who entered into discussions at meetings and those who provided written submissions. NS Power has tried to respond to all input received and incorporate it where consistent with the legislative provisions and where both technically and commercially feasible.

3.1.1 June 17, 2014 Stakeholder Consultation

At this first meeting, NS Power shared a Draft Terms of Reference for the RtR project, and solicited stakeholder response. Responses were received from two stakeholders and the final Terms of Reference were issued on July 11, 2014. These materials are provided in **Appendix 3**.

NS Power made presentations on the Stakeholder Engagement Process, Renewable to Retail Market Opening Background, and the Backup, Top-Up and Spill and Distribution Tariffs. These materials are provided in **Appendix 4**.

The Nova Scotia Department of Energy also delivered a presentation on the amendments to the Act. Please refer to **Appendix 5.**

3.1.2 October 9, 2014 Stakeholder Consultation

At the stakeholder conference on October 9, 2014, NS Power introduced its market design consultant, Robert Cary.

[12] http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/regulatory-initiatives/renewable-to-retail.aspx

At this conference, Mr. Cary presented his Market Design White Paper, outlining four possible market design approaches.[13] Please refer to **Section 7** herein for a fuller description of these alternatives. NS Power also presented an overview on the proposed Distribution Tariff and an initial presentation on the concept of Embedded Cost Recovery.

NS Power requested stakeholder feedback and received eight written responses.

These materials are provided in **Appendix 6.**

3.1.3 December 15, 2014 Stakeholder Consultation

NS Power reviewed stakeholder responses from the October session and created a Strawman Report covering specific subject areas. It noted stakeholder support for the disaggregated market design, identified positions on meter ownership, and collection and billing preferences. Stakeholders indicated a preference for supplier-consolidated billing. Stakeholder views on other topics were summarized and responded to by NS Power including avoided cost calculations, embedded cost recovery, interconnection, distribution tariff development, customer service, and partial service.

Mr. Cary presented his White Paper on Embedded Cost Recovery at this session.

Written responses to the December 15, 2014 conference topics were received from five stakeholders.

These materials are provided in A**ppendix 7.**

[13] The four market design options presented were: Integrated, Disaggregated, Hybrid and Financial.

3.1.4 February 12, 2015 Stakeholder Conference

In response to suggestions from several stakeholders, NS Power invited participants to an information session on February 12, 2015 and presented background information on Rate Setting at NS Power and Open Access and Generator Interconnection Procedures.

These materials are provided in **Appendix 8.**

3.1.5 March 2, 2015 Stakeholder Consultation

On March 2, 2015, Mr. Cary presented his initial Design Basis Development Paper, describing the more detailed design of the disaggregated market model, which NS Power adopted after considering the response of stakeholders to Mr. Cary's October 9 presentation. NS Power presented a proposed work plan and schedule.

Three stakeholders provided written comments on these materials.

These materials are provided in **Appendix 9**.

3.1.6 Materials circulated to Stakeholders on May 21 and June 11, 2015

On May 21, 2015, NS Power issued draft Licenced Retail Supplier (LRS) Terms and Conditions and LRS Participation Agreement, as well as a draft Distribution Tariff with supporting documentation and calculations. These draft materials are provided in **Appendix 11**. In this Application, the revised LRS Terms and Conditions and LRS Participation Agreement are discussed in **Section 8**, and the revised Distribution Tariff is discussed in **Section 9.6**.

On June 11, 2015, NS Power issued drafts of an Energy Balancing Service Tariff, Standby Service Tariff, a new Schedule 4A for OATT, and a presentation providing context on the BUTUS[14] Redesign for Renewable to Retail. These draft materials are provided in **Appendix 12**.

In this Application, the revised EBS, SS and Schedule 4A are presented in **Sections 9.1, 9.2** and **9.3.**

NS Power invited stakeholders to submit Data Requests on these documents.

3.1.7 Stakeholder Data Requests and NS Power Responses

In mid-June, Data Requests (DRs) were received by NS Power from the Board's consultant Multeese Consulting, the Consumer Advocate's consultant, Paul Chernick, Scotian WindFields, and Port Hawkesbury Paper. NS Power received 49 DRs which asked questions on the draft materials issued in May and June, 2015. NS Power emailed responses to the Data Requests on July 3 and July 6, 2015 with an updated Multeese DR-32 issued July 13, 2015. On July 15, 2015, NS Power received DR-35 from Multeese Consulting, Inc. NS Power's response to Multeese DR-35 is provided in **Appendix 13** on pages 124-128.

These materials are provided in **Appendix 13.** Several DR attachments are also provided in electronic format, as Appendix 13A through 13F.[15]

3.1.8 July 22, 2015 Stakeholder Comments and Teleconference

[14] Backup, Top-up and Spill.
[15] As noted above, the Excel workbook for Multeese DR-32 Attachment 1 was issued on July 6, 2015 and reissued on July 13, 2015. It was further updated and issued to stakeholders with the draft RTT draft on July 23, 2015. To avoid filing several similar and superseded workbooks with this Application, NS Power is filing one version of that workbook, newly updated to reflect the latest version of the proposed tariffs, as Appendix 24. To review earlier versions of Multeese 32, the reader is directed to the Renewable to Retail page on the NS Power website at http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/regulatory-initiatives/renewable-to-retail.aspx

NS Power requested comments from stakeholders on its proposed draft Distribution Tariff, LRS Terms and Conditions, EBS, SS, OATT Schedule 4A, and DR Responses by July 15, 2015. This date was extended to July 20, 2015 to accommodate some additional DR responses which were issued on July 6, 2015. No stakeholder comments were received by the Company, but at the request of one stakeholder, NS Power invited all participants to a follow-up teleconference to review certain DR responses on July 22, 2015 and respond to any additional questions or comments from stakeholders. After this discussion, NS Power issued a brief summary and an updated version of SWFI DR-1, both of which are provided in **Appendix 14.** No further comments were received from stakeholders.

3.1.9 Materials circulated to Stakeholders on July 23, 2015

On July 23, 2015, NS Power provided to stakeholders its proposed Renewable to Retail Market Transition Tariff (RTT), a short explanatory presentation and an updated version of Multeese DR-32[16] adding the RTT calculations. Please refer to **Appendix 15.** In this Application, the RTT is discussed in **Section 9.7**.

3.1.10 Stakeholder Comments of August 5, 2015

Upon issuing the draft RTT on July 23, 2015, NS Power requested comments from stakeholders on or before August 5, 2015. No comments from stakeholders on the draft RTT were received by the Company.

3.2 Stakeholder Engagement Post-Application

NS Power has responded to stakeholder contributions through the many interactions that took place during the development of this Application, most significantly in the adoption

[16] The workbook for the July 23, 2015 version has not been included in the Appendices as it has been superseded by the updated workbook provided in **Appendix 24**.

of the disaggregated market design model, adoption of supplier-consolidated billing, and developing proposed tariffs that transparently recover appropriate costs.

The formal regulatory process begins with the submission of this Application. NS Power requests that Intervenors continue to provide feedback with respect to the proposed RtR documents, with a goal of developing a majority view or consensus on many components of this system prior to the formal hearing. In keeping with the Board's Order, NS Power proposes to convene a Settlement Conference in December 2015 in an effort to further this objective, collaboratively develop agreed-upon items and reduce the complexity of the issues to be brought before the formal hearing.

4.0 RENEWABLE SUPPLIER LICENCING AND CODE OF CONDUCT

Section 3E(2) of the Act states as follows:

> (2) Subject to any qualifications prescribed by the regulations, the Board may issue a retail supplier licence to an applicant, subject to any terms and conditions the Board considers appropriate and any terms and conditions prescribed by the regulations."

On May 12, 2015, the UARB issued Draft Board Electricity Retailers Regulations under the *Electricity Act* (Retailers Regulations) and draft Code of Conduct for Renewable Low-Impact Electricity Sales in Nova Scotia (Code). NS Power and several other participants provided comments on the Retailers Regulations and Code on June 10, 2015 in accordance with the UARB's schedule. On July 15, 2015, the UARB issued a revised draft of the Retailers Regulations and Code, addressing this input. These drafts are provided in **Appendix 10.** The Company understands that the Board proposes to publish the final versions after issuing its decision on this Application.

NS Power acknowledges the role of the UARB in licencing Retail Suppliers, and developed these tariffs and other market documents to be consistent with the provisions of the Retailers Regulations and Code.

The Company notes that while the Retailers Regulations stipulate a maximum contract term of five years in the case of Small-Volume customers, they do not provide for a minimum contract period. This creates the potential for gaming through frequent switching by retail customers which could result in cost transfers to NS Power customers.[17] NS Power does not propose a minimum term at this time but reserves the right to propose changes if this matter becomes an issue, as noted in Section 3.2 of the Cary Report.

[17] For example, in the absence of a minimum contract term, a customer on demand billing could potentially switch only for the summer months to keep a demand ratchet in the customer's billing artificially low.

5.0 CERTIFICATION OF RENEWABLE LOW-IMPACT ELECTRICITY

The Retailers Regulations[18] provide that generation facilities serving the RtR market shall obtain certification as low-impact renewable energy. The Nova Scotia Department of Energy will certify generators who propose to provide electricity in the RtR market to a LRS as being duly qualified producers of renewable low-impact electricity generated in-province in accordance with the requirements set out in the Renewable Electricity Regulations (RES). NS Power will rely upon the certification issued by the Province when entering into agreements and providing tariffed services to LRS. NS Power is not and should not be required to verify whether or not a generation facility has satisfied the requirements for electricity standard approval under the RES.

[18] Appendix 10, Section 17. If a Licence Holder is also a generator, they shall obtain certification. If a Licence Holder purchases electricity from a generator, they shall obtain proof of certification.

6.0 NS POWER APPROACH TO RTR MARKET DEVELOPMENT

6.1 Factors Influencing the Approach

As described above, the Company has sought to engage all stakeholders in the development of the RtR framework. While the legislative framework has provided a foundation for the market objectives, the market model, mechanisms, tariffs, procedures and rules have been left to NS Power to develop in consultation with stakeholders. In undertaking this initiative, and in order to inform this proceeding, it is important to outline the various factors which the Company and stakeholders are unable to determine at this stage (and which may not be able to determine until well after the implementation of the RtR market) and which influence the approach to the design:

1. The uncertain pace and scope of market opening.

   NS Power has approximately half a million retail customers. The distribution of customers, demand and energy across residential, commercial and industrial groups is as follows:

Customer Category	Number of Customers	Annual Sales (GWh)	Annual Average Customer Energy Consumption (MWh)	Coincident Demand (MW)	System Coincident Demand-based Load Factor
Residential	456,991	4,217	9.23	1,023.8	47.01%
Commercial	35,477	3,065	86.4	490.2	71.38%
Industrial	2,451	1,544	630.0	205.5	85.77%

   Consumption levels, consumption patterns, and cost to serve these categories differ significantly and NS Power rates reflect this. The effect on the balance of NS Power customers of the loss of customers from bundled service across these categories will differ in the near- and longer-terms.

At this point, there is no information available which would allow NS Power to accurately forecast how much of its customer base will opt for service from LRSs, the composition of this load, or whether any such customers will return to the Company in the near- or longer-term.

This uncertainty supports an approach to market design which is flexible, and an approach to tariff pricing which provides for regular updates as NS Power's cost of serving customers in both the RtR market and under the unbundled rates changes.

2. The limited cost savings produced by customer transfer from NS Power to LRSs (and possible return).

As demonstrated during recent regulatory proceedings (including Demand-Side Management (DSM), large-scale capital, and fuel and non-fuel-related rate proceedings), the Company has limited requirements for new generating capacity in the mid-term, so there is likely little value in terms of avoided utility capacity cost by the displacement of NS Power load with RtR supply.

This circumstance represents a challenge to NS Power's efforts to mitigate any lost contribution to fixed costs arising from a customer's departure and suggests these savings may be overtaken by the incremental capital and operating costs associated with the implementation and management of the RtR market. It also suggests that the potential cost savings, if any, will largely be limited to the differential between the Company's average costs built into its rate structure and the avoided cost produced by a customer's departure.

3. The administrative and capital costs associated with supporting this market opening.

Ongoing RtR market growth will drive the need for adjustments to the Company's metering and billing processes and systems and it is likely that capital investment will ultimately be required to expand the capacity of this system infrastructure.

NS Power's administrative costs associated with RtR market support including processing of RtR customer transactions, meter data management and settlement functions are expected to grow with increasing RtR market uptake.

NS Power will monitor such costs and include any required adjustments in future tariff applications.

In light of the provision in Section 3G(2) of the Act which provides that NS Power customers are not to be negatively affected by this market opening, the Company will defer recognition of the costs incurred by it connection with the development of market design and the regulatory proceeding and recover those costs from Retail Customers at a future date after the RtR market has been established.

6.2 Approach to RtR Market Development

In an effort to minimize the costs and risks arising from the various unknowns associated with the implementation of the RtR market and the development of the associated tariffs, the Company has employed the approach in the sections below.

6.2.1 Market Mechanisms

The Company's approach has:

- Employed market mechanisms in place in other jurisdictions

In Canada, only Alberta and Ontario have full retail access. British Columbia and Newfoundland and Labrador do not have open access, and the remaining provinces have open access markets, limited to wholesale or large industrial and commercial customers. In the United States, 15 states plus the District of Columbia have some degree of retail access.

NS Power is not aware of any other jurisdiction in Canada or the United States that has an electricity retail market restricted to renewable low-impact generation. The Renewable to Retail market opening in Nova Scotia is the first such opening of which NS Power is aware.

The model proposed by NS Power builds, to the extent possible, on learnings from other markets, including the retention of delivery services as a regulated offering (Distribution Tariff), the provision of Transmission service through an Open Access Tariff, the acceptance of the distributor (NS Power) of the role of default supplier, and the requirement to recover embedded costs from transitioning customers.

- Leveraged existing market mechanisms

In developing the proposed market documents, NS Power sought to leverage the current Market Rules, GIP, and OATT to the extent possible. NS Power has utilized the existing Market Rules, GIP, and OATT with amendments to address the unique nature of the RtR market.

In developing the Distribution Tariff, NS Power has utilized and minimally modified the existing Board-approved NS Power Regulations applicable to NS Power's bundled service retail customers, such as connection and disconnection regulations.

6.2.2 Rate Design

The Company's approach has:

- Employed the established Cost of Service and rate design structures

  The Company has maintained the Cost of Service (COS) framework applicable to bundled customer rates in the development of the RtR tariffs. The Company's COSS has been recently vetted through a Board proceeding[19] and therefore will be familiar to many stakeholders.

  Similarly, the Company has, where practical, retained the rate design elements applicable to the Company's associated bundled service rates (such as demand and energy billing components) and has retained the actual pricing where this is appropriate (e.g. Residential and Small General customer charges).

- Utilized annually adjusted rate mechanisms

  The Company has had an annually adjusted rate-setting (AAR) process in place for many years. Through this process, a number of the Company's rates applicable to larger customer load are forecast annually and implemented following the Board's review of the supporting documentation and approval of the associated tariffs.

  This process presents an opportunity to adjust RtR rates which is well-suited to the RtR framework. It will minimize the risk of material errors due to changes in

[19] NS Power 2013 Cost of Service Study, Board Decision 2014 NSUARB 53, March 11, 2014. Please refer to http://nsuarb.novascotia.ca/ under Matter numbers M05473 and M06555.

market factors and should minimize controversy in the rate-setting process as the parties will have an annual opportunity to review and update figures.

NS Power recognizes that a longer term view of RtR rates may be necessary as the market matures; however, in the interim, this represents a practical approach to address the uncertainties of the market.

6.2.3 Approach to Implementation

Once the Board's Decision in this matter has been issued, the Company will need time to complete the following:

Market Procedures	Assessment of the requirement for, and development of, new or amended Wholesale Electricity Market Procedures.
Administrative procedures	Administrative and notification procedures for customer transfers between NS Power and LRS or between LRSs, including the development of forms, timeframes, standards and electronic processes for exchange of information, including the RtR Customer Transaction Request Application as provided in the LRS Terms and Conditions.
Metering	To determine technical requirements for RtR meter installations, costs, change-out processes, and metering data exchange procedures between NS Power and LRSs.
Billing processes	Development of billing format and administrative processes and structures, meter reading, meter repair, meter data management processes and settlement processes.

NS Power corporate administrative requirements	Develop or revise job descriptions and training for employee roles in the business office, customer service and the Nova Scotia Power System Operator. Any other processes or business procedures required to implement the RtR market opening.

NS Power anticipates it will require six (6) months following issuance of the Board's Decision to develop, vet and implement the necessary RtR market mechanisms.

NS Power also recognizes that market changes or other drivers may require changes to the market structures approved by the Board.

Given the uncertainty with the RtR market development it will be important to monitor and report to the Board and stakeholders on market developments. To this end, NS Power proposes an annual filing which summarizes market activity, identifies gaps in the processes and the proposed means to address these if required. For the interim period, it is likely this report will focus on the Company's progress in implementing the procedures required to support this market opening.

6.3 Location of Generation Facility

The RtR framework designed by NS Power assumes that the proposed RtR tariffs and associated cost recovery are applicable to the entire load of a customer opting for RtR service. This is irrespective of the location of the generator relative to the load, whether at opposite ends of the province, within the same distribution zone or the RtR generation is downstream (i.e. behind) NS Power's metering point. To do otherwise would either require a separate set of RtR tariffs be developed to apply in these scenarios or risk contravening the fundamental principles of the enabling RtR legislation – that NS Power's existing customers not be negatively affected by the introduction of RtR competition and customers or LRSs active in this market bear all costs associated with this market opening

Behind-the-Meter Generation

To ensure NS Power customers are not negatively affected by behind-the-meter transactions, in accordance with the requirements of Section 3G(2) of the Act, all RtR tariffs should apply fully to the LRS for the RtR transactions, regardless of the physical arrangement of the generator and the NS Power meter for the RtR customer. To apply the LRS Tariffed Services and the Distribution Tariff to behind-the-meter transactions, the installation of interval revenue-class secondary metering will be required to measure the LRS deliveries to the RtR Customer, for the purposes of settlement of amounts due from the LRS to NS Power.

For further discussion of the issue of Behind-the-Meter generation, please refer to Section 3.5 of the Cary Report (**Appendix 16**).

6.4 Partial Service

The proposed RtR model assumes electricity customers in NS Power's service territory will either take service from NS Power under its bundled utility rates or from a Licenced Retail Supplier, with the associated RtR tariffs in effect. The model does not contemplate that Retail Customers will blend the bundled regulated services and unregulated services within the hour (i.e. a fixed percentage or fixed amount of metered hourly load) or at different times across the year (i.e. by alternating service between NS Power and an LRS within the year). However, for clarity, where a customer has multiple accounts, partial RtR service can be effectively achieved by taking RtR service through some of the individual accounts.

The partial service model is inconsistent with established practice in competitive electricity markets. The opportunity to augment competitive supply with bundled service supply is also contrary to the basic construct of NS Power's rates, which are based on average costs and consumption on an annual basis across all hours. The opportunity to select bundled service at certain time of the year or day would expose all customers to "cherry picking" of these rates. This would potentially undermine the integrity of the RtR market construct and risk creating a cost transfer to NS Power's remaining customers.

This approach is consistent with the requirement of the Act that NS Power not refuse to provide service to a Retail Customer taking service from a Retail Supplier. The Company will continue to provide service to these customers through the Board approved RtR tariffs and will, subject to established regulations, provide service to these customers under bundled service rates in the event the customer elects to the return to NS Power's electricity service.

For further discussion on the issue of partial service, please refer to Section 3.4 of the Cary Report (**Appendix 16**).

6.5 Interruptible Customer Load

Currently, NS Power provides service to 25 Large Industrial customers under the Large Industrial Interruptible Rider (LIIR) of the Large Industrial Tariff. In exchange for agreeing to reduce their load when NS Power is facing capacity and energy shortfalls (i.e. when available firm generation capacity, plus any firm purchases, is temporarily inadequate to meet the system load plus operating reserve requirements), these customers receive a credit against their billed demand. The credit is approved by the Board and is based on the avoided cost of generation enabled by the agreement of these customers to reduce their load within 10 minutes when requested by NS Power.

The Large Industrial Tariff provides that customers are required to provide the Company with five years notice in order to transfer their interruptible service to firm service in order to ensure adequate capacity availability. The Company may permit earlier conversion.

The foundation for this NS Power service offering and its value to the interruptible customers and other customers is the acceptability of interruptible load as operating reserve in accordance with the criteria of the Northeast Power Coordinating Council (NPCC) Directory 5 Reserve. [20]

Transfer of this service offering to the RtR market would face the following challenges:

- It would require revision to the interruptible provision of LIIR tariff or development of an RtR version of this tariff.

- In order not to undermine the value of this service and the NPCC's confidence of the efficacy of this load as a generation alternative, it would likely require a penalty for failure to interrupt be applied to the LRS. This would, in turn, increase the value of the security which the Company would be required to obtain from the LRS.

- Implementation of reliable customer advisory and interruption request procedures and processes in consideration of the fact that an RtR customer's electricity supply is from the LRS and not NS Power.

- The need for an appropriate value exchange, in terms of the interruptibility of the load, amongst NS Power, the RtR customer and the LRS.

[20] The NPCC Directory 5 Reserve can be accessed at: https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

- Any alternative will need to be vetted by the NPCC to ensure the regional reliability coordinator is accepting of the underlying resource as a firm generation proxy.

- Interruptible RtR load would not easily lend itself to the migration to/from utility service applicable to firm customer load, demonstrated by the requirement in the LIIR Tariff for a five-year advance notice by the customer to switch back to firm service from interruptible service.

Addressing the challenges above will be necessary to permit an interruptible customer to migrate to RtR supply and remain as an interruptible customer. Given the limited number of interruptible customers, the uncertainty as to the extent and timing of migration to RtR service by these customers and whether LRSs would be inclined to support interruptible service to its customers, NS Power recommends that requests for transition of an existing interruptible customer to interruptible RtR service be assessed and resolved on a case-by case basis.

Please refer to Section 3.3 of the Cary Report (**Appendix 16**) for a further discussion on the issue of Interruptible Service.

6.6 Summation

Application of the approach described above will place the Company in a position to meet the requirements of the Act in a cost-effective manner and in accordance with accepted utility practice in Nova Scotia. The framework proposed by the Company is transparent, relatively straight forward to implement and administer.

7.0 RTR MARKET DESIGN

7.1 Options for Market Design

In his Market Design White Paper dated October 3, 2014, Mr. Cary described four possible options for the RtR overall market design in Nova Scotia. The four options are summarized here briefly, and described in detail in the Market Design White Paper, along with initial fundamental assumptions and features of market operation. The White Paper and a corresponding presentation delivered by Mr. Cary on October 3, 2014 are provided in **Appendix 6**.

1. Disaggregated tariff option

   This option forms the basis of NS Power's proposed design model. It addresses each stage of the balancing and delivery process as a separate tariff.

   This was the option preferred by most stakeholders who provided feedback, and is most clearly aligned with the enabling legislation. For these reasons, NS Power selected this option.

The three other options considered were:

2. Integrated RtR delivery service tariff

   This option utilizes a top-down tariff approach. Given that the rates paid by customers remaining with NS Power must remain unaffected, the reduction in total Retail Customer rates (relative to NS Power full service rates) should be equal to the cost that NS Power avoids by not supplying the Retail Customer with electricity. The Retail Customer would pay Board approved rates reflecting the NS Power full service rate minus the NS Power cost avoided by the renewable generator's provision of the equivalent quantity of null energy[21] (over the one-year compliance period) and any associated capacity. These rates would be applied on the basis of the Retail Customer metering, and would thus implicitly include the generation balancing, transmission and distribution costs.

3. Hybrid Option

In the hybrid option, transmission and distribution (T&D) costs would be consolidated into a single T&D service payment in accordance with a Board approved joint retail T&D tariff with payments based directly on actual Retail Customer metering. Generation balancing, embedded cost recovery, and avoided capacity credit would merge into a single generation adjustment payment charged on the basis of Retail Customer meter data or on the basis of generation production in respect of that Retail Customer load.

4. Financial Market Option

In this option, a qualifying generator/LRS would inject electricity to the grid and receive from NS Power payment equal to the costs that NS Power avoids as a result. NS Power full service costs and rates would be unaffected for all customers. The Retail Customer would continue to purchase all electricity from NS Power at its full service rates, and pay an agreed RtR adder to the LRS. This design amounts to a null energy sale to NS Power and a retail sale (for retirement only) of renewable attributes.

In addition to the stakeholder discussion at the October 9, 2015 meeting, written feedback was received from eight stakeholders. In its Strawman Report at the December 15, 2014,

[21] Energy (regardless of its generation type), with no renewable attributes, is referred to as null energy.

meeting, NS Power summarized the feedback and proposed that the disaggregated tariff approach would be developed.

7.2 Disaggregated Market Design

7.2.1 Services and Tariffs

The disaggregated models are discussed in the Market Design White Paper (**Appendix 6**). The full development of this model is elaborated in the Cary Report (**Appendix 16**). This market design is illustrated in **Figure 1.**

Figure 1**: Disaggregated Market Design**

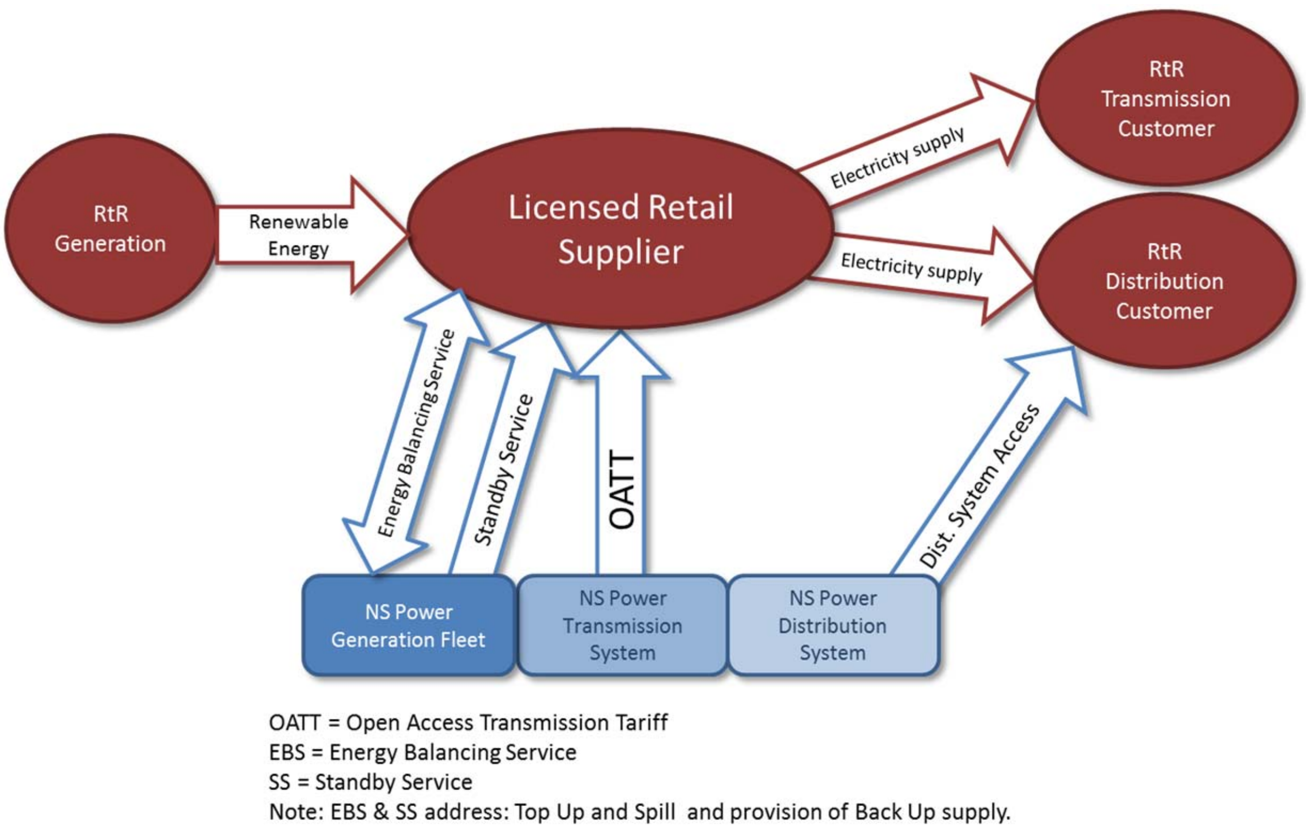


Figure 1 above depicts the elements of the disaggregated RtR tariff approach. In this model, the LRS's electricity is supplied from certified renewable low-impact generators that are owned by the LRS, or a third-party independent generator. In the diagram, the RtR Generation is shown connected to the NS Power transmission system; it could also be connected to the NS Power distribution system.

Generation balancing services are provided to the LRS through the proposed Energy Balancing Service Tariff (EBS) and the Standby Service Tariff (SS). The EBS provides energy supply from the NS Power generation fleet (top-up energy) whenever the output of the LRS's generation output is less than the Retail Customer load, and accepts energy from the LRS's generation at times when the output of the RtR generation exceeds the Retail Customer load. The SS provides firm generation capacity from the NS Power fleet to support the LRS's Retail Customer load requirements in the case where the LRS's generation is unavailable.

The OATT is utilized in the transport of the LRS's electricity to points of delivery from the transmission system. The OATT also provides for the supply and delivery of the Ancillary Services[22] necessary for the conveyance of the electricity supply through the transmission system, to the LRS's designated delivery points.

Distribution connected Retail Customers receive distribution access services as a regulated service from NS Power under the proposed Distribution Tariff. The delivery of "wires-provider" services such as outage management, response to trouble calls, connections and disconnection continues to be the responsibility of NS Power, provided NS Power will invoice the LRS and the LRS will pay NS Power for the costs associated with the services provided by NS Power to the LRS's RtR Customers under the

[22] Ancillary Services are Services that are necessary to support the transport of capacity and energy from generation resources to loads while maintaining reliable operation of the Transmission System in accordance with good utility practice.

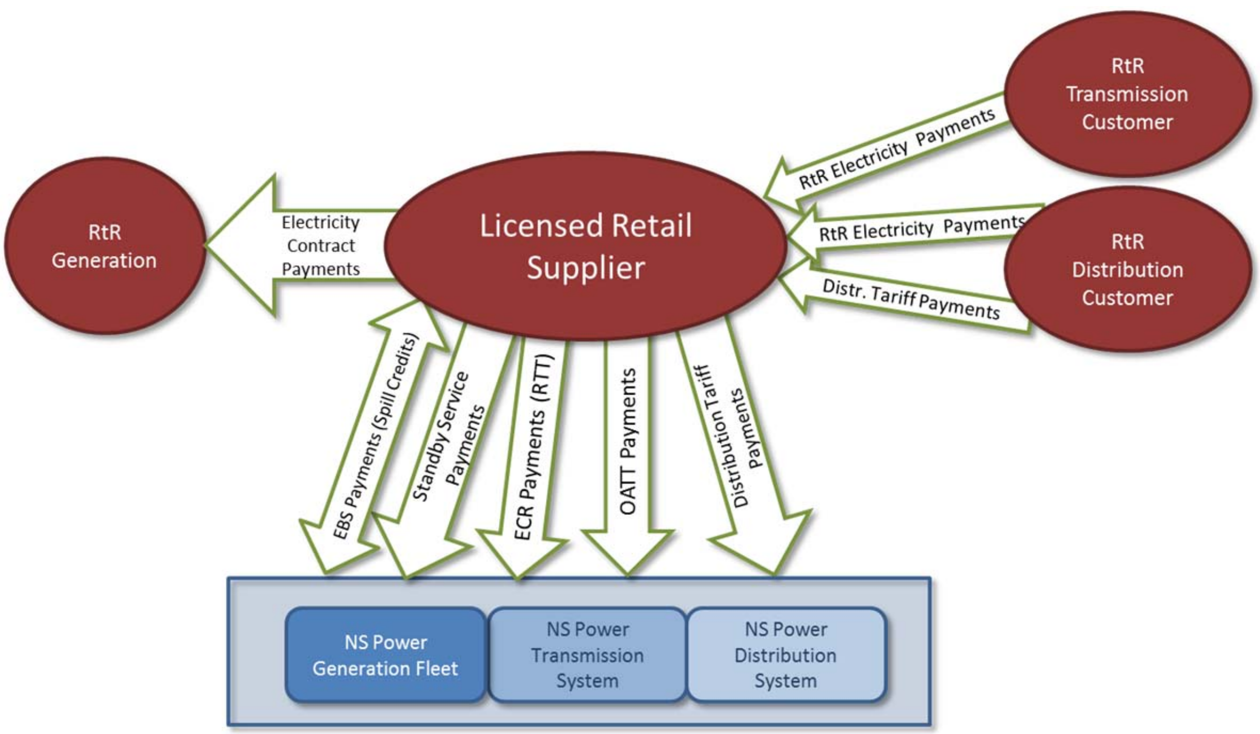
Distribution Tariff. The LRS will have the right to seek reimbursement from the applicable RtR Customer for such costs.

As described in **Section 6.3**, for both transmission and distribution connected generators, the full suite of RtR tariffs apply, including the OATT and the Renewable to Retail Market Transition Tariff.

7.2.2 Flow of Payments

Figure 2 below describes the flow of payments in the disaggregated RtR market design proposed in this Application, and enabled by the proposed tariffs and other documents submitted herein for UARB approval.

Figure 2: Disaggregated Tariff Design - Flow of Payments



In **Figure 2**, there are three payment streams depicted for the RtR supply:

- Payments made in respect of NS Power's provision of tariffed services to the LRS. These LRS Tariffed Services are:

    - EBS – Energy Balancing Service
    - SS – Standby Service
    - RTT – RtR Transition Tariff
    - OATT – NS Power Open Access Transmission Tariff

  These charges will be billed by NS Power and paid by the LRS.

- Payments made by the end-use customer (if distribution-connected) to their LRS for Distribution Access Service under the proposed Distribution Tariff. These charges will be billed to and paid by the LRS who in turn will seek reimbursement for such fees and charges from its RtR Customers. The Board's draft Code requires that any amounts owing under the NS Power Distribution Tariff be charged without markup to the LRS's customers.[23]

- Payments made by the LRS to third party generators under electricity supply contracts. These payments are not addressed within the NS Power tariff structure. This may include payment for certain Ancillary Services provided by third party generators to the LRS per the terms of the NS Power OATT.

[23] Section 10.1 and 10.3 of the Code state as follows:
10.1Where a Licence Holder renders bills on behalf of NS Power, the Licence Holder may not mark-up, add to, aggregate, bundle, unbundle, or otherwise alter the Customer-specific line items and charges requested by NS Power.
//
10.3 Where a Licence Holder renders bills on behalf of NS Power, the Licence Holder shall identify on the bill that the Customer-specific line items and charges from NS Power are passed through from NS Power to the Customer without mark-up or profit to the Licence Holder's advantage.

8.0 LRS TERMS AND CONDITIONS AND LRS PARTICIPATION AGREEMENT

8.1 Purpose

The LRS Terms and Conditions (LRS T&Cs) are designed to govern the relationship between, and set out the various responsibilities of, NS Power and a LRS for customer transactions, billing and settlement. The LRS Participation Agreement binds the LRS and NS Power to the procedures, terms and conditions contained in the LRS T&Cs by incorporating them into the Agreement. Distribution System Access under the Distribution Tariff is provided directly to the Retail Customer by NS Power and is not included in the scope of the LRS Participation Agreement.

The proposed LRS Terms and Conditions and Participation Agreement are provided in **Appendix 18** (the Participation Agreement forms Appendix B of the LRS Terms and Conditions). This version of these documents has been updated from the draft version circulated on May 21, 2015, to better align the documents with the design and other documents, refinement of some procedures and language, and the addition of provisions to address matters such credits assurance and liability which were not addressed in the original draft. Details about the options considered and overall design of the LRS T&Cs can be found in Section 2 of the Cary Report (**Appendix 16**).

8.2 LRS Tariffed Services

As described in Section 2 of the Cary Report, by entering into the LRS Participation Agreement, the LRS agrees to be bound by the LRS T&Cs. The LRS T&Cs address procedures for Retail Customer transactions, metering, Load Settlement and LRS billing. To qualify to receive the LRS Tariffed Services – which comprise the services under the Energy Balancing Service Tariff, Standby Service Tariff, the OATT and the RtR Transition Tariff – the LRS must have a Retail Supplier Licence issued by the Board, execute the LRS Participation Agreement, adhere to the security requirements and become a Market Participant.[24]

The LRS T&Cs provide that the LRS must agree to subscribe to all the LRS Tariffed Services, which, as noted above, consist of the following:

- Renewable to Retail Market Energy Balancing Service (EBS)
- Renewable to Retail Market Standby Service (SS)
- Renewable to Retail Market Transition Tariff (RTT)
- Open Access Transmission Tariff (OATT)

8.3 Key Elements of the LRS T&Cs

<u>Responsibilities:</u>

In the LRS T&Cs, the responsibilities of the LRS and the responsibilities of NS Power are set out with regard to services, payment, point of customer contact, and notification.

The key responsibilities of the LRS under the LRS T&Cs are as follows:

- Procuring Renewable Low-impact Electricity for resale to retail customers.
- Acquiring services under the applicable NS Power tariffs.
- Adhering to the security requirements.
- Obtaining customer authorization for transfers and customer information release to/from NS Power.
- Contracts for sale of electricity to Retail Customers.

[24] To become a Market Participant, the Retail Supplier will execute a Participation Agreement (as defined in the proposed Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules Appendix 1A) with the NSPSO.

- Billing of its Retail Customers (including billing for fees and charges under the Distribution Tariff).
- Adhering to certain of the requirements of the NS Power Regulations identified in the LRS T&Cs.
- Payment of invoices issued by NS Power.

NS Power responsibilities:

- Providing LRS Tariffed Services and issuing invoices to the LRS
- Processing Retail Customer transfer requests
- Providing metering services
- Providing billing and settlement for each LRS
- Maintaining customer information for all Retail Customers/Retail Customer sites

As noted above, the LRS is responsible for having appropriate contractual or other arrangements with its Retail Customer(s) for the supply of renewable low-impact electricity. NS Power will not be responsible for monitoring, reviewing or enforcing such contracts between the LRS and its Retail Customers.

Customer transactions:

The framework for customer transactions is set out in the LRS T&Cs. Prior to the enrolling of a Retail Customer, the LRS is required to complete and submit an application form (RtR Customer Transaction Request Application) signed by both the LRS and the Retail Customer.[25] NS Power will process requests to transfer customers to RtR service, but may refuse to transfer a customer if that customer has not settled amounts owing to

[25] The form of RtR Customer Transaction Request Application has not yet been determined and will need to be developed during the creation of detailed business processes.

NS Power. Some details, such as acceptable timeframes and form of notification remain to be established during business process development.

Prior to accepting an RtR Customer Transaction Request Application for any Retail Customer site that is physically connected to NS Power's transmission system, execution of a separate operating agreement between NS Power's and the LRS's transmission-connected Retail Customer would be required to establish the ongoing operational relationship between these parties. The requirement for this agreement is provided for in the LRS T&Cs.

The intent of the operating agreement would be to establish the general obligations of the transmission-connected customer and NS Power and address operational topics such as: metering, load balance, harmonics, right of way and right of access. The operating agreement would also delineate the unique supply characteristics and arrangement of the customer's facilities and delivery points.

NS Power anticipates the operating agreement would be similar in form to the existing OATT Network Operating Agreement attached as Appendix G to the OATT.[26]

NS Power and the LRS have mutual responsibilities to ensure that customer information is exchanged in order to enable transfers of customers between LRSs and NS Power.

Customer Contact:

The LRS will be the primary contact for their Retail Customers on commercial matters. NS Power will continue to be the contact for distribution access issues or restoration of outages. Education and communication with customers will be required to avoid confusion with respect to customer contact.

[26] The OATT can be found on NS Power's OASIS website, http://oasis.nspower.ca/en/home/oasis/default.aspx

Metering and Billing:

Metering will be done by NS Power, and interval meters with remote polling capability will be used. NS Power Regulations with respect to metering will apply.

NS Power will provide meter readings to the LRS so that they can bill their customers. As noted above, NS Power will also bill the LRS for the costs associated with the Distribution Access Service NS Power provides to the LRS's RtR Customers under the Distribution Tariff. The LRS will have the right to seek reimbursement of such amounts from the applicable RtR Customer.

NS Power will bill the LRS for LRS Tariffed Services based on the LRS's aggregated meter readings monthly, with payment within 20 calendar days and interest on unpaid balances as provided in NS Power Regulation 5.4. Distribution-level meter readings will be adjusted by established loss factors for application to tariffs priced at the transmission level.

Please refer to Sections 3.6 and 3.7 of the Cary Report (**Appendix 16**) for more details on the development of the approach to metering and billing.

Security Requirements:

An LRS will be required to provide the Company, in advance, with security for its obligations to NS Power, including payment of the LRS Tariffed Services or the charges owing to NS Power by the Retail Customer under the Distribution Tariff, regardless of payment history.

NS Power can request security from the LRS (no more frequently than once per calendar month) based upon an amount equal to 200 percent of the forecasted payment for the

LRS Tariffed Services and the DT Charges combined. If the LRS fails to provide the security within three (3) business days, NS Power will be entitled to terminate the Agreement with the LRS and draw upon the security as set out in Section 18 of the LRS Terms and Conditions (**Appendix 18**).

The security can be in the form of cash, a letter of credit, or other security acceptable to NS Power. Costs of a Letter of Credit are to be the responsibility of the LRS.

Default Supplier:

If the LRS is no longer supplying service to its Retail Customers as a result of a failure to meet its obligations to NS Power or having its licence terminated by the Board, the supply of bundled service to the affected Retail Customers will revert to NS Power as the default supplier if no alternate LRS has been identified by the Retail Customer.

8.4 Roles of the LRS T&Cs and Board Electricity Retailers Regulations and Code of Conduct

The Retailers Regulations have been issued by the Board in draft form, and, as noted above, the Company understands the Retailers Regulations will be finalized after the Board issues its decision in this matter. In order to be licenced to sell electricity in Nova Scotia, Licence Holders must demonstrate to the Board that they comply with the Retailers Regulations and Code of Conduct.

NS Power relies on the Retailers Regulations and Code of Conduct and does not attempt to duplicate their requirements in its proposed tariffs and other market documentation. As appropriate, NS Power’s tariffs work in conjunction the Retailers Regulations and provide the level of detail needed for market implementation. **Figure 3** compares provisions of the Retailers Regulations to the LRS T&Cs, where these impact NS Power’s role.

Figure 3: Retailers Regulations and LRS Terms and Conditions

Subject	Draft Electricity Retailers Regulations	Draft LRS Terms and Conditions
Section 10 to 16 Compliance Period	A Compliance Period over which the amount of Renewable Low-Impact Electricity supplied shall equal or exceed the total sales plus transmission and distribution losses, with a provision for a refund to customers if this is not so.	Not covered in LRS T&Cs. This requirement is repeated in the Renewable to Retail Market Energy Balancing Service Tariff.
Section 17 to 18 Proof of Certification	Proof of Certification of the Electricity as Renewable Low-Impact Electricity.	NS Power relies on Retailers Regulations.
Section 19 to 21 Licence suspension, Cancellation, and Reinstatement	Sets out rules governing suspension, cancellation or reinstatement of the Licence.	If a Licence is suspended, no action is taken under the LRS T&Cs. If a Licence is cancelled, NS Power may terminate the LRS Tariffed Services. Upon reinstatement of a Licence, the LRS Tariffed Services will be available to the Licence Holder again.
Section 22 to 25 Licencing Reporting and Compliance Reporting	Lists the compliance reports required to be submitted by Licence Holders.	NS Power relies on Retailers Regulations.

Subject	Draft Electricity Retailers Regulations	Draft LRS Terms and Conditions
Section 26 Transfer Requests	The Retailers Regulations states that the Licence Holder will not make a request for transfer of a Customer unless the Customer has agreed to a contract, and the Licence Holder has complied with the provisions to the Regulations and Code of Conduct.	In Section 11, the LRS T&Cs contain detail regarding processing of transfer requests, including the categories of transaction, NS Power's right to refuse to transfer a customer who has outstanding debt to NS Power, and other practical matters. More detail, such as acceptable intervals and the form of Customer Transaction Requests, will be established during the creation of detailed business processes.
Section 28 to 34 Contracts	Licence Holder requirements such as the ways in which a Contract may take effect, and rules for Contract assignment, including notifying NS Power of a Contract assignment, sale or transfer.	Section 9 of the LRS T&Cs sets out certain requirements that must be met with respect to the LRS's contractual arrangements with its Retail Customers.
Section 35 to 37 Records Retention	Type of records to be held and length of retention.	NS Power relies on Retailers Regulations.

Subject	Draft Electricity Retailers Regulations	Draft LRS Terms and Conditions
Section 38 to 44 Dispute Resolution Process	Process the UARB will use in dealing with complaints, including provision for NS Power to initiate a complaint, and the use of NS Power as default supplier if a Customer cancels its Contract with the Licence Holder due to its contravention of the Act, Regulations or Code of Conduct.	For disputes about matters in the Retailers Regulations and Code of Conduct, NS Power relies on the Retailers Regulations. In cases of billing disputes between NS Power and the LRS, Section 15 of the LRS T&Cs sets out the administrative process if a failure of payment by the LRS occurs.
Section 45 to 64 Requirements for Small-Volume Customers	Special protections for Customers served by the Domestic Service or Small General Tariffs. Includes the provision that if a Small-Volume Customer cancels a contract with a Licence Holder under S. 60, the Customer is returned to NS Power Bundled service.	NS Power relies on Retailers Regulations.

8.4.1 Stakeholder Input to the LRS Terms and Conditions

As noted above, NS Power responded to Data Requests and comments issued by stakeholders on draft documents, including drafts of the LRS Participation Agreement and the LRS Terms and Conditions. These Data Requests provided useful expansion of information on the LRS Terms and Conditions. In response to Data Requests from the Board's Consultant, Multeese, NS Power reworded a number of the sentences and concepts in the LRS Terms and Conditions. Additional changes were also made to align the documents with the design. A copy the stakeholder Data Requests and NS Power's responses is provided in **Appendix 13.**

NS Power submits to the UARB for approval, the LRS Participation Agreement and the LRS Terms and Conditions, as set out in **Appendix 18**. As part of a proposed Compliance filing, NS Power may make further changes to the documents to accommodate any changes that arise from this proceeding, settlement discussions with stakeholders or the subsequent implementation period.

9.0 RTR TARIFFS

As described above, NS Power has developed tariffs for Energy Balancing Service (EBS) and Standby Service (SS) and introduced Schedule 4A of the OATT to address the requirement for the LRS to have a supply of top-up and backup services. The specifics of each of these tariffs, along with amendments to the OATT and the new Distribution Tariff are described below.

9.1 Energy Balancing Service Tariff (EBS)

9.1.1 Components of the EBS

NS Power's EBS tariff provides for electricity supply (top-up) to the LRS when the LRS's load exceeds its generation supply and payment for energy (spill) when the LRS's generation supply exceeds its load. Top-up and spill amounts are tracked hourly to produce a net top-up or spill amount for each hour of service. Top-up energy will be provided by NS Power to the LRS under the EBS as null energy, not renewable low-impact energy. Please refer to Section 5 of the Cary Report (**Appendix 16**) for a comprehensive discussion of the development and operation of the EBS Tariff.

The EBS Tariff contains a monthly Administration Charge intended to recover from a LRS, the administrative cost of providing EBS.

As proposed herein, the Administration Charge, the top-up and spill rates will be reviewed and may be adjusted annually based on the calculated values of this energy for the following year.

The top-up amount includes a Fixed Cost Adder to provide for the recovery of generation-related fixed costs classified to energy in accordance with the Company's Cost of Service model.

The spill rate will include an adjustment to reduce the spill rate paid where a LRS's annual spill energy exceeds its customer load by greater than 10 percent. The escalated discounts will be reviewed by the Company and could be revised if necessary as part of the annually adjusted rates process.

As the top-up rate includes provision for recovery of energy-classified generation-related fixed costs, the Standby Service charge provides for recovery of the generation-related fixed costs classified as demand per the Company's Cost of Service methodology.[27] Combined, the two services provide for full recovery of generation-related fixed costs related to the provision of the EBS and Standby Service and avoid cost transfer to other customer classes when the LRS is taking these services from NS Power.

Rates included in the EBS Tariff are provided in **Figure 4** below with the source document references. The rates will be adjusted and submitted to the Board as part of the Company's Annually Adjusted Rate process in the fourth quarter of the year to take effect in the following year.

[27] The Standby Service Demand Charge reflects the COSS-based demand-related generation costs net of costs of ancillary generation services recovered under the OATT.

Figure 4: Energy Balancing Service Tariff rates

Subject	Rate	Source
Administrative charge	$1,053.03/month (per LRS)	Based on incremental administrative costs, similar to OATT
Top-up rate		**Appendix 19A**, provided electronically.
Incremental Fuel Cost	6.650 cents per kWh	
Fixed Cost Adder	3.309 cents per kWh	
Total	**9.959 cents per kWh**	
Spill rate (before excess spill adjustment for annual spill amounts greater than 10% of annual LRS load)	5.27 cents/kWh	

9.1.2 Stakeholder Contributions to the EBS

As noted above, the EBS Tariff was issued to stakeholders in draft on June 11, 2015. Stakeholder Data Requests gave NS Power the opportunity to explain the rationale and derivation for the charges, and provide some example calculations based on scenarios supplied by stakeholders. In one case (Multeese DR-27), NS Power modified the wording in the draft tariff to make the meaning clearer. The Data Requests and NS Power responses can be found in **Appendix 13**. Subsequent to the filing of its DR responses, NS Power determined that a revision was required to the calculation of the fixed cost adder of the energy charge in the EBS Tariff. **Appendix 19A** contains the Company’s revised workbook showing EBS Tariff charge calculations.

NS Power submits to the UARB for approval, the EBS Tariff as set out in **Appendix 19.** As noted above, the Company proposes the rates included in the tariff be adjusted annually.

9.2 Standby Service Tariff (SS)

NS Power's SS Tariff provides generation capacity to an LRS when the LRS's generation sources are unavailable. Please refer to Section 5 of the Cary Report (**Appendix 16)** for additional information with respect to the SS Tariff.

9.2.1 Components of the SS

The SS Tariff contains a monthly Administration Charge intended to recover from LRSs the administrative cost of providing Standby Service. The SS Tariff also includes a monthly demand charge to provide for the recovery of the cost of providing this service (i.e. generation-related fixed costs classified to demand in accordance with the Company's Cost of Service model net of OATT capacity-based ancillary service charges).

The demand charge will be applied to the Monthly Standby Contract Demand (MSCD). The MSCD is developed through the application of class monthly demand adjustment factors to the LRS's firm demand at the time of system coincident firm load peak in each month at transmission delivery points (i.e. inclusive of distribution system losses).

Prices included in the SS Tariff are provided in **Figure 5** below with the source document references. The rates will be adjusted annually within the Annually Adjusted Rates framework based on forecast fuel costs for the following year.

Figure 5: Standby Service tariff rates

Subject	Rate	Source
Administrative charge (1)	$1,053.03/month (per LRS)	Based on incremental administrative costs, similar to OATT
Standby Service	$5.370/month (per kilowatt of monthly standby contract demand)	**Appendix 12**, page 22 and Multeese DR-29, found in **Appendix 13D**

(1) This is in addition to the administrative charge in the Energy Balancing Service Tariff.

9.2.2 Stakeholder Contributions to the SS Tariff

A draft of the SS Tariff was issued to stakeholders on June 11, 2015.

In addition to the Data Requests mentioned in Section 9.1.2 (which dealt with both EBS and SS Tariffs), in Multeese DR-29, NS Power provided the derivation of rates in the SS Tariff. As noted above, the Data Requests and NS Power responses can be found in **Appendix 13.**

9.2.3 Interruptibility and Capacity

In further developing the RtR design basis, NS Power and its consultant reviewed the possibility of NS Power customers on the LIIR rider being eligible for RtR service. The implications of this have not been sufficiently analyzed or discussed with stakeholders, and any determination is premature. NS Power has modified the draft SS Tariff and removed a reference to “interruptible retail customers of the LRS” in Note 4 under Applicability. Please refer to the discussion in Section 6.5 above.

NS Power submits to the UARB for approval the SS Tariff as set out in **Appendix 20**. As noted above, the Company proposes the rates included in the tariff be adjusted annually.

9.3 OATT Schedule 4A

As set out by NS Power in response to Multeese DR-33,[28] the current wholesale market approach to imbalance between supply and demand includes two elements:

1. Scheduled hourly energy balancing service requirements, which are addressed by the existing Backup/Top-up/Spill (BUTUS) tariff; and

2. Deviations of the actual hourly quantities from the scheduled hourly quantities, which are addressed by Schedule 4 of the OATT.

This two-part approach was determined to be unsuitable for the RtR market for the following reasons:

(a) The expected diversity of RtR load over multiple delivery points from the transmission system would make hourly load forecasting very onerous. It would also have questionable value in that it would not alter total loads at each delivery point.

(b) The asymmetric nature of the top-up charge and spill credit under the proposed EBS tariff, with the top-up charges including energy-related fixed cost recovery, would yield a material incentive for a LRS to under-forecast its load at times of expected top-up. Such under-forecasting would lead to LRS avoidance of the

[28] This Data Request can be found in Appendix 14.

energy-related fixed cost recovery and could adversely affect the NS Power System Operator's (NSPSO) system management and optimization.

(c) Settlement under the two-part approach would be significantly more complex than under the proposed RtR market approach.

Having determined that the EBS Tariff should provide for settlement against actual metered imbalances only, NS Power gave consideration to the implications with respect to the OATT Schedule 4. The application of OATT Schedule 4 as it stands would result in overlapping settlement for the marginal energy cost of imbalances which would not be appropriate.

Accurate forecasting is important to the NSPSO in the management of the system. The load forecasting element has limited value due to the embedding of RtR loads at delivery points; however, the generation forecasting element remains important. Schedule 4A is designed to provide the forecasting incentive element of the existing Schedule 4, as applicable to the production from non-dispatchable RtR generation.

Please refer to Section 5.3.2 of the Cary Report (**Appendix 16**) for additional information with respect to OATT Schedule 4A.

NS Power requests the OATT be amended to include the new OATT Schedule 4A proposed by NS Power as well as a revised 2014 OATT Schedule 4, both as set out in in **Appendix 21** which shall be added immediately following OATT Schedule 4 in the OATT.

9.3.1 Stakeholder Contributions to OATT Schedule 4A

A draft of Schedule 4A was issued to stakeholders on June 11, 2015. The rationale for Schedule 4A was provided in Multeese DR-33. As noted above, the Data Requests and NS Power responses can be found in **Appendix 13.**

9.4 Other OATT Amendments

The OATT[29] came into effect on November 1, 2005 and provides the procedures and requirements for eligible customers to obtain transmission services necessary for use of the NS Power transmission system. The OATT supports Wholesale Market transactions, supply to NS Power's native load customers and export transactions. Under the OATT, Transmission Services are offered by the NS Power System Operator (NSPSO). The OATT also includes NS Power's Generator Interconnection Procedures, applicable to generating facilities connected to the transmission system.

Please refer to Section 6 of the Cary Report (**Appendix 16)** for more detail on the development of the approach to Transmission.

To facilitate the introduction of Renewable to Retail competition, the following amendments to the OATT are required:

- Amendments to enable LRSs to become Transmission Customers under the OATT and receive Transmission Services required for their aggregate RtR electricity transactions. Changes proposed to the OATT and the Wholesale Electricity Market Rules are required to make the LRS eligible to be a "Transmission Customer" under the OATT. The LRS must come within the definition of a Transmission Customer in order to be able to conduct transactions

[29] The existing OATT can be found on the NS Power website at http://oasis.nspower.ca/en/home/oasis/default.aspx

on the NS Power transmission system. Changes also confirm that the LRS is a Network Customer in respect of its aggregated RtR load.

- Amendments to establish the appropriate Transmission Services for the RtR market structure by confirming that Network Integration Transmission Service under Part III of the OATT is applicable to the LRS's RtR transactions on NS Power's transmission system to accommodate geographically dispersed RtR customer load. (Network Integration Transmission Service is firm transmission service, comparable to NS Power's use of the transmission system.)

- Amendments to distinguish any unique procedure requirements and/or exclusions which are specific to the RtR market versus the Wholesale Market.

- Amendments to reflect the incorporation of the new Schedule 4A and the generation forecasting element.

The proposed amendments to the OATT are attached as **Appendix 22**. For ease of reference the amendments (in addition to the amendments to OATT Schedule 4 referred to above) are contained in the following sections:

(i) Table of Contents
(ii) Part I, Common Provisions : Section 1.0 (Definitions)
Section 3.0 (Ancillary Services)
(iii) Part III – Network Integration: Preamble
Section 30.4 (Operation of Network Resources)
(iv) Attachment E – Standards of Conduct – Revision to title on p.1
(v) Attachment G – Network Operating Agreement - Correction to Section reference on first page.

NS Power has not reviewed these changes with stakeholders other than as discussed through the market framework development. The Company will review these changes in the technical conference which is currently scheduled to be held on September 11, 2015.

NS Power submits to the UARB for approval the amendments to the OATT set out in **Appendix 22**.

9.5 Generator Interconnection Procedure Amendments

NS Power's Generator Interconnection Procedures (GIP) were established with the OATT in 2005 and subsequently revised by the Company with the approval of the Board in 2010. The GIP is applicable to generating facilities connected to the transmission system. The GIP and its appendices define the processes required to interconnect a generating facility to the NS Power Transmission System. The major elements of the GIP include:

- Interconnection Queue – Queue position assigns access rights to transmission system.

- Defines procedures for interconnection studies, timing, and cost responsibilities.

- Facilities cost responsibilities – defines who pays for interconnection related facilities.

- Standard Generator Interconnection and Operating Agreement template – addressing the obligations of the parties throughout the life-cycle of the generating facility.

The GIP's queuing and study procedures were substantially revised in 2010 to incorporate a "First-ready, First-served" model instead of a "First-come, First-served," and as such, market readiness standards are defined in the 2010 GIP.

NS Power is proposing two amendments to the GIP to accommodate the introduction of the RtR market. The proposed amendments can be summarized as follows:

- Addition of a new market readiness milestone in Section 7.2 for Interconnection Queue advancement applicable to RtR generating facilities owned by a LRS. This is required as otherwise the project cannot have Interconnection Studies completed and proceed through the interconnection process. Please refer to **Appendix 27**. (Note that NS Power is also proposing a minor administrative amendment to the definition of "Market Participant" to reflect the proposed revision to the title of the Market Rules).

- Addition of an amendment to Section 11.4.2 of the Standard Generator Interconnection and Operating Agreement (Appendix 6 to the GIP) clarifying that costs associated with the addition of all network upgrades resulting from the interconnection of RtR generation are the responsibility of the RtR generation interconnection customer and are not eligible for repayment by NS Power. This approach is proposed to be in alignment with the legislative principle that retail suppliers and their customers are not to be negatively affected by the provision of service by retail suppliers to their customers that would otherwise be the responsibility of NS and its customers. This amendment also required the addition of several new defined terms in Article 1. Please refer to **Appendix 28**.

9.6 Distribution Tariff and NS Power Regulations

The Distribution Tariff (DT) proposed by the Company governs the relationship between NS Power and the Retail Customer. Access to NS Power's distribution system access (e.g. wire service) is provided to the Retail Customer through the Distribution Tariff. The Distribution Tariff includes terms and conditions and rates payable by the Retail Customer.

The Distribution Tariff is not applicable to transmission-connected Retail Customers.

The service provided by NS Power to the Retail Customer under the Distribution Tariff is referred to as Distribution System Access. Distribution System Access provides for the connection of the Retail Customer to NS Power's distribution system, but does not include the supply of the electricity itself. It provides delivery of electricity supplied by the LRS on the distribution system and related services including connections, disconnections, line and service extensions, inspection services, meter services, power restoration, meter reading, and customer service.

NS Power provides Distribution Access Service directly to the Retail Customer, and will continue to be the point of Retail Customer contact for inquiries about the distribution service and outage management. As the RtR market in Nova Scotia will use Supplier-consolidated billing, NS Power will invoice the LRS for the amount owing under the DT for each of its Retail Customers. The Distribution Tariff charges will be paid by the LRS and then collected by the LRS from its Retail Customer.

The rates included in the Distribution Tariff reflect rates applicable to the Retail Customer's rate class, aligned to bundled service rate classes.

A**ppendix 11** contains documents issued to stakeholders relating to the development of the Distribution Tariff including a detailed Strawman model on how the rates were developed.

The proposed Distribution Tariff can be found in **Appendix 17**. This version of the tariff document has been updated from the draft version circulated on May 21, 2015, to reflect further refinement of the tariff.

Appendix 17A contains the supporting analysis on the adjustment to DT rates arising from the DR process as set out in NS Power's response to DR-21 (**Appendix 13**).

9.6.1 Stakeholder Contributions to the Distribution Tariff

As noted above, the Distribution Tariff was issued in draft to stakeholders on May 21, 2015. Based on stakeholder DRs, further internal development and alignment with other elements of the design, changes and further refinements have been made to the proposed Distribution Tariff. The Data Requests and NS Power responses can be found in **Appendix 13**.

9.6.2 NS Power Regulations

In order to ensure the NS Power Regulations would continue to apply to Retail Customers connected to the Distribution System, NS Power has proposed an amendment to Section 2.2 of the NS Power Regulations to confirm that an Agreement is deemed to exist between the Retail Customer and the Company for the provision of Distribution System Access as well as the provision of electric service. NS Power has also proposed an amendment to the NS Power Regulations to make clear that the Net Metering Regulations and alternate billing did not apply to RtR Customers. The proposed revisions also necessitated the addition of several defined terms in the Section 1.1 (Definitions and Interpretation).

For ease of reference the amendments are contained in the following sections of the NS Power Regulations:

(i)	Section 1.1	Interpretation and Definitions
(ii)	Section 1.3	Infringement of Regulations
(iii)	Section 2.2	Agreement
(iv)	Section 3.6.2	Availability
(v)	Section 3.6.3.2	Customer
(vi)	Section 5.3	Alternate Billing Plans

NS Power submits to the UARB for approval: (a) the Distribution Tariff as set out in **Appendix 17;** and (b) the amendments to the NS Power Regulations in respect of the Distribution Tariff as set out in **Appendix 26**.

9.7 Renewable to Retail Market Transition Tariff

Section 3G(2) of the Act provides that NS Power customers are not to be negatively affected by the introduction of the RtR market and that the costs of developing this market are to be recovered from suppliers and customers active in this market.

The primary potential harm faced by NS Power customers as a result of the implementation of the RtR market opening is that costs incurred by the Company to serve customers opting for RtR service, either in the past or in anticipation of serving this load in the future, could be transferred to NS Power's remaining customers in the form of increased rates.

The Cost of Service Model approved by the Board and employed through the development of the proposed RtR tariffs means that the costs in question are the fixed costs (i.e. not fuel) classified in the Cost of Service as generation-related. This is because transmission related costs will continue to be recovered through the OATT, and distribution and retail related costs will be recovered through the Distribution Tariff.

The amount to be recovered through the proposed RtR Market Transition Tariff (RTT) is the departed Retail Customer's portion of generation-related fixed costs as determined by NS Power's Cost of Service less generation-related fixed cost amounts recovered through other RtR tariffs.

The proposed RTT includes a demand charge and an energy charge; the former of which utilizes the Standby Service demand charge; the latter applies the fixed cost component of the EBS top-up energy rate. Combined and applied to the load served by the LRS, the RTT will result in full recovery of the Company's fixed costs.

Prices included in the RTT are provided in **Figure 6** below with the source document references. The rates will be adjusted annually within the Annually Adjusted Rates framework based on forecast fuel costs for the following year.

Figure 6: RtR Market Transition Tariff

Subject	**Rate**	**Source**
Energy Charge Components	Cents per kWh	
Fixed Cost Adder from Energy Balancing Service Tariff	3.309	**Appendix 14** and **Appendix 19A**, also provided electronically.
Annually Adjusted Energy Savings Credit		
Annual Energy Cost Adjustment		
Total (Energy Charge)	3.309	
Demand Charge Components	Dollars per kW	
Demand Charge from Standby Service Tariff	$5.370	**Appendix 14**
Annually Adjusted Demand Savings Credit	$0.000	
Total (Demand Charge)	$5.370	

The Company recognizes its responsibility to mitigate this cost. However, the Company's ability to mitigate this cost is severely limited by its ongoing requirement to maintain generation capacity in the event the RtR customers return to NS Power's service, either at their option or as the result of an action of the LRS.

Similarly, with respect to operating savings, it appears that savings emerging from Retail Customer departure are limited. While there may be savings in some administrative areas (e.g. collections, billing), these are likely small and may be overcome by additional costs arising from development and management of the RtR market.

In the near-term, there may be fuel savings produced by the reduction in load resulting from the departure of RtR customers as the incremental costs of serving additional NS Power load is generally higher than the average cost of fuel embedded in customer rates. To recognize this, the RTT proposed by NS Power provides for an adjustment to the RTT energy charge. It should be noted that while this adjustment will generally result in a reduction of the RTT Energy Charge, it may be an increase should the marginal costs of electricity on the system fall below the average fuel cost.

Ultimately, the charges included in RTT will be a function of the volume and class make-up of departing load and utility operational matters arising in the future. In order to minimize cost and risk to all parties associated with this uncertainty, NS Power proposes that the RTT be adjusted as part of the Annually Adjusted Rates process, based on the Company's forecast of its avoided fixed and variable costs.

Embedded cost recovery was discussed in the stakeholder sessions on December 15, 2014, where Robert Cary presented his White Paper on Embedded Cost Recovery.[30] NS Power received responses from some stakeholders with respect to this presentation. Stakeholder understanding of embedded costs was also assisted by NS Power's

[30] Please refer to Appendix 7.

presentation on rate setting on February 12, 2015,[31] and developed further in Mr. Cary's March 2, 2105 presentation on the Design Basis.[32]

The RTT was developed and issued to stakeholders on July 23, 2015. Please refer to Section 8 of the Cary Report (**Appendix 16)** for additional information with respect to the RTT.

NS Power submits to the UARB for approval the RTT as set out in **Appendix 23**.

9.8 RtR Tariff Summary

The above RtR tariffs are intended to provide appropriate cost recovery from Retail Customers and Retailer Suppliers and to ensure NS Power's bundled service customers are not negatively affected as stipulated under Section 3G(2) of the Act. In accordance with the rates proposed, transmission service will be recovered through the OATT; Distribution service costs will be recovered through the Distribution Tariff and the costs of supporting RtR generation and customer load misalignment is recovered through the EBS Tariff and the SS Tariff. Generation-related fixed costs which cannot be mitigated by NS Power will be recovered through the RTT.

Due to the blend of fixed and variable cost components (demand and energy charges), the per kilowatt breakdown of these costs by LRS is dependent on the composition of the LRS's customer portfolio (i.e. mix of various customer classes) and how closely this load matches the LRS's generation source. However, for illustrative purposes, **Figure 7** below provides the breakdown of RtR costs by tariff for Domestic, General and Large Industrial (Firm) Rate classes under the assumptions that the LRS's customers are from a single rate class, the customers have the same load profile characteristics as the NS Power class average, there is no excess annual spill, and deliveries from the LRS will

[31] Please refer to Appendix 8.
[32] Please refer to Appendix 9.

meet directly 60 percent of LRS load with top-up and spill representing 40 percent of LRS load each.

Figure 7: Illustrative Unit Revenues by RtR Tariffs*

Unit revenues in cents per KWh at the point of delivery to customer's premise			
TARIFF	**RATE CLASS**		
	DOMESTIC CLASS	GENERAL RATE CLASS	INDUSTRIAL LARGE FIRM SERVED AT DISTRIBUTION VOLTAGE
DT	4.0	1.5	0.6
OATT	1.6	1.5	1.1
EBS	2.0	1.9	1.9
SS	1.2	0.7	0.3
RTT	2.6	2.6	2.5
Total	11.5	8.2	6.5

***Note: This table is for illustrative purposes only. Figures may not add up precisely to the totals due to rounding.**

Appendix 24, provided electronically, contains a numerical example of the tariff calculations. This Excel workbook supersedes the one provided electronically as Attachment 1 to Multeese DR-32[33] and a version provided[34] with the stakeholder copy of the RTT.

As noted above, LRS subscription to all the LRS Tariffed Services (i.e. all tariffs except the Distribution Tariff), plus RtR Customer subscription to the Distribution Tariff are

[33] Provided July 13, 2015.
[34] Provided July 23, 2015.

required for NS Power to recover the costs attributed to the RtR market suppliers and their customers.

9.9 Net Metered Customers

NS Power provides metering and billing services under Regulation 3.6 whereby electricity consumers can sell to NS Power their excess self-generated renewable electricity. If a net-metering customer chooses to obtain electricity from a LRS, the net metering arrangement with NS Power will cease. As noted above, NS Power has proposed an amendment to the NS Power Regulations to make clear that the Net Metering Regulation does not apply to RtR Customers.

10.0 POST MARKET OPENING

It is the Company's expectation that refinements to this market model and the associated tariffs and procedures will be required as the market develops. The timing of these refinements will be determined by the pace of and scope of Retail Customer take-up. It may be this will occur irregularly.

Ultimately the RtR market development is a market-driven initiative, the nature of which is likely to be dynamic, changing as market conditions change, new technologies emerge and the utility's cost and rate structures change.

Recognizing this, NS Power recommends that it provide an annual report to the UARB, identifying the state of market development and any changes required to Board approved tariffs. It is anticipated the report will advise the Board of RtR market take-up, ongoing engagement with LRSs, emerging issues, and anticipated changes to Board approved tariffs and processes, if any.

The report would serve to assist the Board in its oversight of this market and maintain alignment between the Company's processes and RtR Market development in Nova Scotia.

11.0 MARKET RULES AND PROCEDURES

The Nova Scotia electricity market was opened to wholesale competition on February 1, 2007. The Wholesale Electricity Market Rules (Market Rules) are applicable to wholesale customers, eligible customers under the OATT and the operation of the bulk electricity supply system. The Market Rules define the rights and obligations of NSPSO and market participants. The recent amendments to the Act require NS Power to create a new or amend the existing set of Market Rules to facilitate the RtR market.

NS Power has sought to leverage the existing Market Rules in developing amendments for the RtR market.

The amendments proposed are driven by four primary objectives:

- To broaden the scope of the existing Wholesale Market Rules and Procedures to include the new RtR market while preserving the provisions applicable to the Wholesale Market;

- To enable the LRSs who are licenced by the Board to become Market Participants under the Market Rules, and thereby eligible to obtain Transmission Service and Ancillary Services under the OATT and to receive other tariffed services through the LRS Participation Agreement with NS Power;

- To expand the scope of the Wholesale Market Advisory Committee to include the RtR market; and

- To provide for any unique market rule and procedure requirements and/or exclusions that are specific to the RtR market and include them in the amended Market Rules and Procedures.

The NSPSO will consult with the Wholesale Market Advisory Committee with respect to the proposed amendments and they will be submitted for review by Stakeholders, in accordance with the processes laid out in Market Rule 2.4 and Market Procedure MP-05 (Amendments to Market Rules, Standards, Codes and Market Procedures).

The process for amending the Market Rules is established under Market Rule 2.4.2. Subject to review and input of the Wholesale Market Advisory Committee and Stakeholders, the Nova Scotia Power System Operator will publish the amended Market Rules in accordance with Market Rule 2.4 and Market Procedure 5.

The proposed Market Rule amendments are set out in **Appendix 25** and will require adoption by the Nova Scotia Power System Operator. NS Power submits these amendments to the Board for review for the purposes of ensuring alignment with the approved RtR design framework.

The Wholesale Market Procedures are documents that describe the procedures, processes and forms to be used by the NSPSO, Market Participants and others in fulfilling their respective obligations or exercising their rights under the Market Rules. Market Procedures provide more detailed descriptions of the requirements for various activities than are specified in the Market Rules.

NS Power does not anticipate the requirement for material amendments to Market Procedures at this time. This will be reassessed by the Company after the UARB Decision.

12.0 IMPLEMENTATION PLAN

Upon a Decision from the Board on this Application, there will be the following outstanding items left for determination:

- Assessment of the requirement for New or amended Wholesale Electricity Market Procedures.

- Administrative and notification procedures for customer transaction requests for customer transfers between NS Power and LRS or between LRSs.

- Development of forms, timeframes and electronic processes for exchange of information, including the RtR Customer Transaction Request Application as provided in the LRS Terms and Conditions.

- Determine technical requirements for RtR meter installations, costs, change-out processes, and metering data exchange procedures between NS Power and LRSs.

- Billing format and processes, settlement processes and other details with respect to LRS consolidated billing.

- Develop or revise job descriptions and training for employee roles in the business office and NSPSO.

- Any other processes required to implement the RtR market opening.

- Changes or amendments to any of the proposed tariffs, the LRS Terms and Conditions, the LRS Participation Agreement, or the proposed amendments to the NS Power Regulations, the OATT, the Market Rules or the GIP to reflect matters identified in the Regulatory proceeding, alignment with the Board's Decision and implementation matters.

In addition to the foregoing, the Board will finalize the Retailers Regulations and Code. NS Power would respectfully request the Company and other stakeholders be provided with an opportunity to provide further comments on any subsequent revisions to the Retailers Regulations and Code in order to ensure concordance with the Board's decision and the final RtR documents issued in this proceeding.

Based on the foregoing, NS Power would request that any order of the Board in this matter not be made effective until a period of six months after the issuance of its Decision (Implementation Period) in order to allow for the completion and finalization of the above matters (collectively referred to as the Outstanding Items).

Finally, in the event any of the assumptions upon which the RtR documents were prepared, as set out herein, are determined to have been incorrect or to the extent that the Decision on this Application differs from the basis upon which the Application is premised, NS Power would need to consider the requirement for revisions to the documents in order to ensure that customers are not negatively affected and Retail Suppliers and Retail Customers are responsible for all costs associated with the RtR service as provided for under Section 3G(2) of the Act.

13.0 CONCLUSION

Over the past year, NS Power has engaged with stakeholders to develop a Renewable to Retail market model which complies with the legislative framework enacted by the Province, is aligned with established electric utility rate-making practice in Nova Scotia and balances complexity and flexibility to accommodate varying paces and scopes of Renewable to Retail market take-up in Nova Scotia.

Within this Application, the Company has proposed a comprehensive suite of tariffs and market rules necessary to enable this market opening. The Company believes it has complied with the intent and spirit of the Act and provided appropriate assurance to ensure that NS Power's customers who continue to take service under regulated bundled service are not harmed by this change to the market. Likewise, NS Power believes it has proposed a model which does not unduly burden participants in the new Renewable to Retail Market.

The Company looks forward to continuing engagement on this matter as the formal portion of this matter begins with this filing. NS Power intends to continue to fully engage with stakeholders to identify potential improvements to the Application and will work collaboratively in an effort to resolve and or minimize outstanding issues.

14.0 RELIEF SOUGHT

NS Power respectfully requests the Board's approval of:

1. The Distribution Tariff as set out in **Appendix 17**;

2. The LRS Participation Agreement and the LRS Terms and Conditions, as set out in **Appendix 18,** subject to the qualifications noted herein;

3. The Energy Balancing Service Tariff as set out in **Appendix 19**;

4. The Standby Service Tariff as set out in **Appendix 20**;

5. Amendments to 2014 OATT Schedule 4 and the new OATT Schedule 4A, both as set out in **Appendix 21**;

6. The proposed amendments to the OATT as set out in **Appendix 22**;

7. The Renewable to Retail Market Transition Tariff as set out in **Appendix 23**;

8. The amendments to the NS Power Regulations as set out **Appendix 26**;

9. The amendments to the Generator Interconnection Procedures and Standard Generator Interconnection and Operating Agreement as set out in **Appendices 27** and **28**.

NS Power is also proposing amendments to the Wholesale Electricity Market Rules as set out in **Appendix 25**, which will require approval of the Nova Scotia Power System Operator. NS Power has submitted these amendments to the Board for review for the purposes of ensuring the amendments align with the approved RtR design framework.

Additionally, as described above, NS Power will monitor the administrative costs associated with supporting this market opening, including modifications to its metering and billing processes and systems and any capital investment that may be required. NS Power proposes to include these costs in future tariff applications.

In addition to the foregoing, NS Power respectfully requests that any order of the Board in this matter not be made effective until a period of six months after the issuance of its decision in order to allow for the completion and finalization of the Outstanding Items as set out in **Section 12** herein and the status of such matters and any changes to the tariff rates be included in a Compliance Filing to be submitted by the Company to the Board for approval.

Electricity Act

CHAPTER 25 OF THE ACTS OF 2004

as amended by

2010, c. 14; 2011, c. 15; 2013, c. 34

© 2014 Her Majesty the Queen in right of the Province of Nova Scotia
Published by Authority of the Speaker of the House of Assembly
Halifax

This page is intentionally blank.

CHAPTER 25 OF THE ACTS OF 2004
amended 2010, c. 14; 2011, c. 15; 2013, c. 34

An Act Respecting Electricity

Table of Contents

(The table of contents is not part of the statute)

Short title

1 This Act may be cited as the *Electricity Act*. 2004, c. 25, s. 1.

Interpretation

2 **(1)** In this Act,

(a) "Board" means the Nova Scotia Utility and Review Board;

(aa) "Minister" means the Minister of Energy;

(aaa) "municipal utility" means the Board of Commissioners of the Berwick Electric Commission, The Electric Light Commissioners for Riverport, in the County of Lunenburg or an electric utility of the Municipality of the District of Guysborough, the Town of Antigonish, the Town of Lunenburg or the Town of Mahone Bay;

(ab) "public utility" means any person that transmits, delivers or furnishes electric power or energy and is regulated as a public utility under the *Public Utilities Act*, but does not include a retail supplier;

(b) "retail customer" means a person who uses, for the person's own consumption in the Province, electricity that the person did not generate;

(c) "retail supplier" means a person who is authorized to sell renewable low-impact electricity in accordance with this Act and the regulations, but does not include a wholesale customer;

(d) "wholesale customer" means Nova Scotia Power Incorporated or a municipal utility.

(2) Commencing on such date as prescribed in the regulations, "renewable electricity" includes hydroelectricity whether generated in or imported into the Province. 2004, c. 25, s. 2; 2010, c. 14, s. 1; 2011, c. 15, s. 1; 2013, c. 34, s. 2.

Public Utilities Act

2A Notwithstanding Section 117 of the *Public Utilities Act*, where there is a conflict between this Act and that Act, this Act prevails. 2010, c. 14, s. 2.

Minister has supervision and management

2B (1) The Minister has the general supervision and management of this Act and the regulations.

(2) The Minister may establish and administer policies, programs, standards, guidelines, objectives, codes of practice, directives and approval processes under this Act. 2010, c. 14, s. 2.

Wholesale customers and electricity

3 (1) Effective on the date prescribed in the regulations and, for greater certainty, notwithstanding Section 303 of the *Municipal Government Act*, wholesale customers may purchase electricity from any competitive supplier.

(2) Nova Scotia Power Incorporated shall develop and file with the Board for approval an open access transmission tariff to enable the purchase of electricity for the purpose of subsection (1) and, for greater certainty, Section 77 of the *Public Utilities Act* does not apply.

(3) The tariff referred to in subsection (2) must ensure open and non-discriminatory access to wholesale customers.

(4) Nova Scotia Power Incorporated shall develop and maintain a system to facilitate the import and export of electricity from the Province for the purpose of this Section.

(5) The Board has all the power and authority necessary to implement this Section. 2004, c. 25, s. 3.

Program for customer to generate electricity

3A (1) A public utility may develop and maintain a program that will permit any customer to generate electricity for the customer's own use and to sell any excess electricity to the public utility at a rate equivalent to the rate paid by the customer for electricity supplied to the customer by the public utility.

(2) The program must provide that

(a) only electricity generated by a customer that is renewable low-impact electricity qualifies for the program;

(b) as a condition of participation, the customer transfer or assign all emission credits or allowances arising from the use of renewable energy sources to the public utility to enable the public utility to comply with the requirements of any enactment regulating emissions, but for no other purpose;

(c) the capacity of the customer's generator be sized to meet the expected annual consumption of the customer; and

(d) customers may have multiple meters under one account within a defined distribution zone.

(3) Any program developed and maintained pursuant to subsection (1) must receive the approval of the Board before its implementation by the public utility.

(4) On or before November 1, 2010, Nova Scotia Power Incorporated shall submit to the Board for approval a program as described in subsection (1) that permits customers to generate up to one megawatt of electricity. 2010, c. 14, s. 3.

Application of Public Utilities Act to retail suppliers

3B Notwithstanding the *Public Utilities Act*,

(a) a retail supplier is not a public utility to which the *Public Utilities Act* applies unless the retail supplier is deemed to be a public utility by the regulations; and

(b) the *Public Utilities Act* applies to a retail supplier who is deemed to be a public utility by the regulations, subject to any restrictions prescribed by the regulations. 2013, c. 34, s. 3.

Retail customers and renewable low-impact electricity

3C (1) Effective on the date prescribed in the regulations,

(a) a retail supplier who meets the requirements in Section 3D may sell to a retail customer; and

(b) a retail customer, other than a customer of a municipal utility, may purchase from such a retail supplier, renewable low-impact electricity generated within the Province.

(2) Nova Scotia Power Incorporated shall not refuse to provide service to a retail customer on the basis that the customer purchases renewable low-impact electricity from a retail supplier.

(3) The Board has all the power and authority necessary to implement this Section. 2013, c. 34, s. 3.

Authority to act as retail supplier

3D **(1)** No person shall act or purport to act as a retail supplier unless the person has been issued a retail supplier licence pursuant to Section 3E.

(2) Subsection (1) does not apply to a person who is

(a) deemed to be a public utility by the regulations; or

(b) a member of a class or category of retail suppliers prescribed by the regulations. 2013, c. 34, s. 3.

Retail supplier licence

3E **(1)** A person may apply for a retail supplier licence in the form and manner prescribed by the regulations.

(2) Subject to any qualifications prescribed by the regulations, the Board may issue a retail supplier licence to an applicant, subject to any terms and conditions the Board considers appropriate and any terms and conditions prescribed by the regulations.

(3) The holder of a retail supplier licence may apply to amend the licence in the form and manner prescribed by the regulations.

(4) Where an application is made pursuant to subsection (3), the Board may

(a) amend the retail supplier licence, subject to any terms and conditions the Board considers appropriate and any terms and conditions prescribed by the regulations;

(b) cancel the retail supplier licence and grant a new retail supplier licence, subject to any terms and conditions the Board considers appropriate and any terms and conditions prescribed by the regulations; or

(c) deny the application.

(5) The Board may, in its discretion, and shall, if prescribed by the regulations, amend, suspend, reinstate or cancel a retail supplier licence. 2013, c. 34, s. 3.

Limits on transfer or assignment of licence

3F No person shall transfer or assign a retail supplier licence unless the Board, in its discretion, permits the person to do so or the transfer or assignment is permitted by the regulations. 2013, c. 34, s. 3.

Nova Scotia Power Incorporated obligations

3G **(1)** Notwithstanding Section 77 of the *Public Utilities Act*, on or before the applicable date prescribed by the regulations, Nova Scotia Power Incorporated shall develop in consultation with stakeholders, and file with the Board for approval, any tariffs, procedures and standards of conduct and any amendments to existing tariffs, procedures and standards of conduct that are necessary to facilitate the purchase of renewable low-impact electricity as provided for in Section 3C, including

(a) a new or amended open access transmission tariff;

(b) a distribution tariff;

(c) a new or amended backup/top-up service tariff;

(d) a new or amended non-dispatchable supplier spill tariff;

(e) new or amended interconnection procedures;

(f) new or amended market rules; and

(g) any other tariffs, procedures or standards of conduct prescribed by the regulations or that the Board requires Nova Scotia Power Incorporated to develop or amend in order to facilitate the purchase of renewable low-impact electricity as provided for in Section 3C.

(2) In reviewing and approving the tariffs, procedures and standards of conduct required to be developed or amended pursuant to this Section, the Board shall be guided by the following principles:

(a) customers of Nova Scotia Power Incorporated and persons who, at the coming into force of this Section, are independent power producers or hold feed-in tariff approvals within the meaning of the regulations are not to be negatively affected if some retail customers choose to purchase renewable low-impact electricity from a retail supplier;

(b) retail suppliers and their customers are to be responsible for all costs related to the provision of service by retail suppliers to their customers that would otherwise be the responsibility of Nova Scotia Power Incorporated and its customers. 2013, c. 34, s. 3.

Renewable electricity standards

4 **(1)** Commencing January 1, 2006, or such other date as prescribed in the regulations, a person who sells or supplies electricity to a customer shall comply with the renewable electricity standards set out in the regulations.

(2) Renewable electricity standards referred to in subsection (1) must require that a minimum amount of electricity is produced from renewable sources. 2004, c. 25, s. 4; 2011, c. 15, c. 2.

Public Utility

4A **(1)** A public utility shall

(a) permit generators that qualify under this Section to connect a renewable low-impact electricity-generation facility to its electrical grid in the manner provided by the regulations; and

(b) pay for the electricity generated in accordance with the tariff set by the Board pursuant to this Section.

(2) When requested by the Governor in Council, the Board shall set the tariffs to be paid by a public utility pursuant to this Section.

(3) In setting a tariff pursuant to this Section, the Board shall make allowance for the matters set out in the regulations.

(4) In setting a tariff pursuant to this Section, the Board shall determine

(a) the class or classes of generation facility that qualify for a particular tariff;

(b) whether a tariff is to be adjusted periodically and, where it is to be adjusted, the basis for the adjustment;

(c) the effective date for commencement of a tariff;

(d) the duration of a tariff; and

(e) the terms and conditions under which payment is to be made by a public utility to generators.

(5) In setting a tariff pursuant to this Section, the Board may exercise the same powers and authority granted to it under the *Public Utilities Act*.

(6) A public utility is entitled to recover through its rate base the tariffs paid by it pursuant to this Section on the basis approved by the Board under the *Public Utilities Act*.

(7) The tariffs set pursuant to this Section apply to renewable low-impact electricity generated by the following classes of generation facilities:

(a) wind power;

(b) biomass, including the electricity produced from a combined heat and power plant;

(c) small-scale in-stream tidal;

(d) developmental tidal arrays; and

(e) other generation facilities as provided by the regulations.

(8) In order to qualify as a generator under this Section, the generator must be one of the following and comply with the requirements of the regulations:

(a) a council of a band for a band located in the Province as defined under the *Indian Act* (Canada);

(b) a municipality;

(c) a not-for-profit body corporate;

(d) a community economic-development corporation;

(e) a co-operative; or

(f) any other entity permitted by the regulations. 2010, c. 14, s. 4.

Procurement of renewable low-impact electricity

4B **(1)** Where

(a) a public utility intends to procure renewable low-impact electricity, from one or more independent power producers with generation facilities located in the Province, under a long-term power-purchase agreement; or

(b) the Governor in Council directs a procurement of renewable low-impact electricity from one or more independent power producers with generation facilities located in the Province under a long-term power-purchase agreement,

the Governor in Council may appoint a person to act as a renewable electricity administrator to conduct the procurement.

(2) A renewable electricity administrator appointed under subsection (1) holds office for the term and subject to such conditions as determined by the Governor in Council.

(3) The Board shall fix fees and expenses of a renewable electricity administrator in performing the functions and duties provided in this Section.

(4) The fees and expenses referred to in subsection (3)

(a) must be paid to the renewable electricity administrator by the Board in such amount as determined by the Board; and

(b) may include the cost of retaining experts and legal counsel to provide the renewable electricity administrator with advice on technical and legal matters.

(5) The Board may recover the costs under subsection (4) from public utilities in the same manner it recovers its other expenses under Section 15 of the *Public Utilities Act*.

(6) A public utility shall provide notice to the Minister at least ninety days before the date it intends to initiate a procurement under clause (1)(a).

(7) Where the Governor in Council appoints a renewable electricity administrator for a procurement under subsection (1), the administrator, instead of the public utility, shall issue a request for proposals and award the contract or contracts for the procurement.

(8) Where the Governor in Council does not appoint a renewable electricity administrator for a procurement under clause (1)(a) within sixty days from the date of receipt of the notice under subsection (6), the public utility may issue a request for proposals and award the contract or contracts for the procurement.

(9) A public utility shall procure all renewable low-impact electricity under a request for proposals that contains the requirements set out in the regulations.

(10) A renewable electricity administrator shall evaluate and choose successful independent power producers and provide a written decision to the public utility and to each bidder in the manner and within the time prescribed by the regulations.

(11) Within thirty days after the receipt of the written decision referred to in subsection (10), the public utility may appeal the decision to the Board for errors of law, jurisdictional errors or breaches of natural justice.

(12) Where a renewable electricity administrator has selected one or more independent power producers for the supply of renewable low-impact electricity to a public utility, the public utility shall enter into the agreements necessary to evidence the procurement.

(13) The Board shall allow a public utility to recover from its rate base the costs of the public utility's contracts referred to in subsection (12) on the basis approved by the Board under the *Public Utilities Act*. 2010, c. 14, s. 4.

Public consultation required

4C **(1)** Within twelve months of the coming into force of this Section, the Minister shall complete a public consultation on future policy, plans, programs and regulations with respect to

(a) emerging technologies that may affect the supply and demand for electricity in the Province;

(b) market trends in the supply and demand for energy that may affect prices for electricity in the Province, including those relating to energy efficiency and conservation; and

(c) emerging trends in the governance, organization, performance and accountabilities of persons who provide electricity generation and conveyance to electricity customers.

(2) The Minister may engage the services of experts, consultants and facilitators to assist with the consultation required by subsection (1).

(3) The Minister shall table in the Assembly a written report on the consultation undertaken pursuant to subsection (1) if the Assembly is then sitting or, where the Assembly is not then sitting, file it with the Clerk of the House within two months of completion of the consultation. 2013, c. 34, s. 4.

Regulations

5 **(1)** The Governor in Council may make regulations

(a) setting out the date or dates required for the purpose of subsection 2(2), 3(1), 3C(1), 3G(1) or 4(1);

(b) respecting the tariff referred to in subsection 3(2);

(c) respecting import and export rights;

(ca) prescribing classes or categories of retail suppliers who are deemed to be public utilities and any provisions of the *Public Utilities Act* that do not apply with respect to them;

(cb) prescribing classes or categories of retail suppliers who do not require retail supplier licences to act or purport to act as retail suppliers;

(cc) prescribing tariffs, procedures and standards of conduct for the purpose of clause 3G(1)(g)~~.~~[;]

(d) respecting renewable electricity standards, their administration and enforcement;

(da) prescribing terms and conditions required to be included in a power-purchase agreement;

(db) prescribing costs to be recovered in a tariff set by Board;

(dc) prescribing the terms that independent power producers are required to meet to qualify for the program under Section 4A;

(dd) prescribing types of generation facilities for the purpose of clause 4A(7)(e);

(de) prescribing the form of application and the procedure for considering an application by a generator to participate in the program under Section 4A;

(df) delegating responsibilities to a renewable electricity administrator;

(dg) respecting the certification or decertification of generation facilities;

(dh) respecting the monitoring of generation facilities for compliance with this Act and the regulations;

(di) respecting the interconnection of generation facilities with the electrical grid;

(dj) prescribing entities for the purpose of clause 4A(8)(f);

(dk) providing for the development of terms and conditions required to be included in a request for proposals;

(dl) prescribing the contents of any notice required to be given to the Minister by a public utility;

(dm) prescribing the qualifications for a renewable electricity administrator;

(dn) assigning additional responsibilities to a renewable electricity administrator;

(do) requiring compliance by a renewable electricity administrator with policies and procedures;

(dp) respecting records to be maintained by, reporting by and the audit of the records of a renewable electricity administrator;

(dq) respecting written decisions of a renewable electricity administrator;

(dr) authorizing the Minister to appoint a renewable electricity standard regulations administrator and describing the duties and responsibilities of the administrator;

(ds) providing for administrative penalties to be assessed by a renewable electricity standard regulations administrator in order to enforce compliance with the regulations;

(dt) providing for appeals or reviews of the decisions of a renewable electricity standard regulations administrator by the Board;

(du) respecting standards that biomass sources must meet in order to qualify as a source of renewable low-impact electricity;

(e) defining any word or expression used but not defined in this Act;

(f) respecting any other matter the Governor in Council considers necessary or advisable to carry out effectively the intent and purpose of this Act.

(1A) The Minister shall make regulations requiring the achievement of forty per cent renewable electricity by 2020.

(1B) The Board may make regulations

(a) prescribing the form and manner of applying, and the procedure for considering an application, for a retail supplier licence or an amendment to a retail supplier licence;

(b) prescribing fees relating to any matter provided for in this Act or the regulations;

(c) prescribing the terms and conditions of a retail supplier licence;

(d) respecting the amendment, suspension, reinstatement or cancellation of a retail supplier licence;

(e) respecting the transfer or assignment of a retail supplier licence.

(2) The exercise by the Governor in Council or the Board of the authority contained in this Section is regulations within the meaning of the *Regulations Act*. 2004, c. 25, s. 5; 2010, c. 14, s. 5; 2011, c. 15, s. 3; 2013, c. 34, s. 5.

Proclamation

6 This Act comes into force on such day as the Governor in Council orders and declares by proclamation. 2004, c. 25, s. 6.

Proclaimed - January 22, 2007
In force - February 1, 2007

Nova Scotia POWER
An Emera Company

PO Box 910 ● Halifax, Nova Scotia ● Canada ● B3J 2W5

April 30, 2014

Doreen Friis
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

Re: **<u>Initiation of UARB proceeding for Renewable to Retail Engagement pursuant to Electricity Act</u>**

Dear Ms. Friis:

The amended Electricity Act[1] provides:

3C (1) Effective on the date prescribed in the regulations,

(a) a retail supplier who meets the requirements in Section 3D may sell to a retail customer; and

(b) a retail customer, other than a customer of a municipal utility, may purchase from such a retail supplier,

renewable low-impact electricity generated within the Province.

(2) Nova Scotia Power Incorporated shall not refuse to provide service to a retail customer on the basis that the customer purchases renewable low-impact electricity from a retail supplier.

[1] Electricity Reform (2013) Act, 1st Sess., 62nd General Assembly, NS, 2013, Ch. 34, amending Electricity Act, R.S.N.S. 2004, c. 25.

(3) The Board has all the power and authority necessary to implement this Section.

[...]

3G (1) Notwithstanding Section 77 of the Public Utilities Act, on or before the applicable date prescribed by the regulations, Nova Scotia Power Incorporated shall develop in consultation with stakeholders, and file with the Board for approval, any tariffs, procedures and standards of conduct and any amendments to existing tariffs, procedures and standards of conduct that are necessary to facilitate the purchase of renewable low-impact electricity as provided for in Section 3C, including

(a) a new or amended open access transmission tariff;
(b) a distribution tariff;
(c) a new or amended backup/top-up service tariff;
(d) a new or amended non-dispatchable supplier spill tariff;
(e) new or amended interconnection procedures;
(f) new or amended market rules; and
(g) any other tariffs, procedures or standards of conduct prescribed by the regulations or that the Board requires Nova Scotia Power Incorporated to develop or amend in order to facilitate the purchase of renewable low-impact electricity as provided for in Section 3C.

(2) In reviewing and approving the tariffs, procedures and standards of conduct required to be developed or amended pursuant to this Section, the Board shall be guided by the following principles:

(a) customers of Nova Scotia Power Incorporated and persons who, at the coming into force of this Section, are independent power producers or hold feed-in tariff approvals within the meaning of the regulations are not to be negatively affected if some retail customers choose to purchase renewable low-impact electricity from a retail supplier;

(b) retail suppliers and their customers are to be responsible for all costs related to the provision of service by retail suppliers to their customers that would otherwise be the responsibility of Nova Scotia Power Incorporated and its customers.

Regulations are anticipated in the near future which will provide the date by which NS Power shall make its application to the Board for approval as contemplated by section 3G. In the interim, NS Power wishes to commence the consultation process also contemplated by section 3G. In that regard, NS Power requests that the Board open a proceeding through issuance of a proceeding Notice establishing dates for registration of interventions and that it issue direction for advertising of such Notice. This will allow NS Power to ensure those wishing to participate are given notice and opportunity to formally register. NS Power will use the participants list that is generated for issuance of further communications and invitations associated with this consultation process.

NS Power suggests the Notice be run in two Saturday editions of the Chronicle Herald and Cape Breton Post on May 10 and May 17 and suggests that Interventions be filed with the Board by May 30.

If the Board has any questions or concerns about the above request, please do not hesitate to contact the undersigned.

Yours truly,

Nicole Godbout

Nicole Godbout
Regulatory Counsel

c: Stephen McGrath
Nancy Rondeaux
Interested Parties

NOVA SCOTIA UTILITY AND REVIEW BOARD

NOTICE IN CONNECTION WITH RENEWABLE TO RETAIL SALES OF ELECTRICITY

NOTICE IS HEREBY GIVEN that recent amendments to the *Electricity Act* (*Act*) allow a retail supplier to sell renewable low impact electricity generated within Nova Scotia to a retail customer.

Under the *Act,* Nova Scotia Power Incorporated (NSPI) is directed to develop, in consultation with stakeholders, and file with the Nova Scotia Utility and Review Board (Board) for approval, any tariffs, procedures and standards of conduct, and any amendments to existing tariffs, procedures and standards of conduct, that are necessary to facilitate the purchase of renewable low impact electricity.

INTERESTED PARTIES MAY PARTICIPATE in NSPI's consultation process and subsequent application before the Board. Notice of such intention to participate must be filed with the Board not later than **Friday, May 30, 2014**.

NSPI will use the participant list for the issuance of further communication in connection with this consultation process. Notice of Intention to Participate should be sent to the Clerk of the Board by email at board@gov.ns.ca; or to the office of the Board at 1601 Lower Water Street, Halifax, NS B3J 3P6.

Full details of the matter can be found on the Board's website www.nsuarb.novascotia.ca, Matter Number M06214, at the offices of the Board, 1601 Lower Water Street, Halifax, or by contacting the Clerk of the Board at (902) 424-4448, by fax at (902) 424-3919, by email at board@gov.ns.ca.

ORDER **M06214**

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE ELECTRICITY ACT

- and –

IN THE MATTER OF A PROCEEDING Concerning Sales of Renewable Low Impact Electricity Generated within Nova Scotia by a Retail Seller to a Retail Customer pursuant to the Electricity Act

BEFORE: Peter W. Gurnham, Q.C., Chair

O R D E R

WHEREAS by Application dated April 30, 2014, Nova Scotia Power Incorporated (NSPI) requested the Board initiate a process for consultation by NSPI with stakeholders in connection with sales of renewable low impact electricity generated within Nova Scotia;

AND WHEREAS Section 3G(1) of the *Electricity Act* provides as follows:

> 3G (1) Notwithstanding Section 77 of the Public Utilities Act, on or before the applicable date prescribed by the regulations, Nova Scotia Power Incorporated shall develop in consultation with stakeholders, and file with the Board for approval, any tariffs, procedures and standards of conduct and any amendments to existing tariffs, procedures and standards of conduct that are necessary to facilitate the purchase of renewable low-impact electricity as provided for in Section 3C, including
>
> (a) a new or amended open access transmission tariff;
> (b) a distribution tariff;
> (c) a new or amended backup/top-up service tariff;
> (d) a new or amended non-dispatchable supplier spill tariff;
> (e) new or amended interconnection procedures;
> (f) new or amended market rules; and
> (g) any other tariffs, procedures or standards of conduct prescribed by the regulations or that the Board requires Nova Scotia Power Incorporated to develop or amend in order to facilitate the purchase of renewable low-impact electricity as provided for in Section 3C.

IT IS ORDERED that NSPI initiate the consultation process.

IT IS FURTHER ORDERED that NSPI publish the attached Notice in the Halifax Chronicle Herald and the Cape Breton Post on Saturday, May 10, 2014 and Saturday, May 17, 2014.

DATED at Halifax, Nova Scotia, this 2nd day of May, 2014.

Doreen Friis

Clerk of the Board

DRAFT June 17, 2014

Renewable to Retail Market Opening

Terms of Reference

1) Objective

To develop and implement a framework in Nova Scotia for competitive renewable electricity supply to retail customers, as directed by the Electricity Reform Act (2013), in alignment with the Province's timelines.

2) Introduction

The NS Electricity Reform Act was enacted on December 12, 2013. The Act enables NS Power's retail customers to purchase renewable low-impact electricity generated in Nova Scotia from any licensed competitive supplier.

The Act stipulates that NS Power shall develop in consultation with stakeholders, and file with the Board for approval, any new or amended tariffs, procedures and standards of conduct that are necessary to facilitate the purchase of renewable low-impact energy.

The Regulations will provide the date by which NS Power will submit its application to the Utility and Review Board.

3) Approach

In support of the development and implementation of the NS renewable to retail market, NS Power will:

a) Consult and collaborate with stakeholders to gain and share knowledge and experience with market structures and systems;
b) Consider successful approaches used in other jurisdictions with active retail markets;
c) Develop and circulate Strawmen to stakeholders for comment on significant issues or opportunities.
d) Consider potential capital or operating expenditures required by NS Power to support the market opening, including infrastructure, metering, billing, and other system modifications;
e) Create drafts of documentation for review and input of stakeholders;
f) Convene technical conferences throughout the process;
g) Prepare and file UARB application; and

h) Implement required changes based upon the UARB decision.

4) Scope

As set out in section 3G(1) of the Electricity Reform Act (2013), NS Power is directed to develop in consultation with stakeholders, and file with the Board for approval, any new or amended tariffs, procedures and standards of conduct that are necessary to facilitate the purchase of renewable low-impact energy including:

a) a new or amended open access transmission tariff (OATT);
b) a distribution tariff;
c) a new or amended backup/top-up service tariff;
d) a new or amended non-dispatchable supplier spill tariff;
e) new or amended interconnection procedures;
f) new or amended market rules; and
g) any other tariffs, procedures or standards of conduct prescribed by the regulations or that the Board requires Nova Scotia Power Incorporated to develop or amend in order to facilitate the purchase of renewable low-impact electricity.

5) Consultation Framework

NS Power will seek stakeholder input throughout the process, and will schedule stakeholder sessions to facilitate direct stakeholder input.

A timeline for meetings and filings is provided below for the consultation process. It is intended that this will enable establishment of consensus on issues in an efficient manner, anticipating a filing with the UARB in the third quarter of 2015.

6) Criteria

The solution shall be guided by the following criteria:

a) Customers of NSPI and persons who are independent power producers or hold feed-in tariff approvals are not to be negatively affected if some retail customers choose to purchase renewable low-impact electricity from a retail supplier.
b) Retail suppliers and their customers are to be responsible for all costs related to the provision of service by retail suppliers to their customers that would otherwise be the responsibility of NS Power and its customers.
c) Existing NSPSO market mechanisms and systems will be leveraged to the extent possible in the implementation, i.e. by leveraging existing OATT infrastructure and processes, where applicable.

d) The market administration solution will seek scalability in its implementation, to respond to market uptake.

7) Timeline Summary

a)	Stakeholder meeting #1	Q2 2014
b)	Develop initial strawman models	Q3 2014
c)	Stakeholder meeting #2	Q3 2014
d)	Incorporate stakeholder feedback	Q4 2014
e)	Stakeholder meeting #3	Q4 2014
f)	Complete proposed new or amended Tariffs*	Q2 2015
g)	New or amended Tariffs, Procedures, etc. filed with UARB	Q3 2015
h)	NS Power implementation complete; organizational readiness	Q2 2016

*Note: Additional stakeholder consultation as required

------Original Message------
From: MacDougall, David
To: NICOLE GODBOUT
To: Mahaney, Sara
Cc: LANDRIGAN, DAVID
Cc: McGrath, Stephen T
Subject: Renewable to Retail Market Opening Terms of Reference
Sent: Jun 30, 2014 2:53 PM

Nicole, further to your request for comments on the Terms of Reference by July 2 please note the following comments on behalf of PHP which reflect the points we raised at the recent Technical Conference:

1. Consideration should be given in the Scope section to possibly allowing an earlier phased market opening by putting in place the necessary structures for a transmission connected customer to access the retail market. As a new distribution regime will likely take more time to put in place it may not be necessary to wait such a long time to put the transmission regime in place considering the existing OATT which can be leveraged off.
2. The Scope should make provision for early determination of what is meant by customers of NSPI not being “negatively affected”. This appears to be equated in the materials to stranded costs (slide 6 of the Stakeholder Engagement Deck). Very early determination of this issue would be helpful for possible participants to gauge whether there will be any opportunity to actually economically avail of the renewable to retail regime.
3. Specific consideration should be given to the issue of market aggregation as part of the Scope as market aggregation may be a key driver to allow for the regime to be a success.

David, I understand from an e-mail I sent to Nicole earlier today that she may be out until after July 2 so I have copied you and would ask that you make sure these comments get to the right NSPI representative dealing with the Terms of Reference on this matter.

As some of these items may have a tie in at some point to ongoing Gov’t action on this matter I have copied Steve McGraw with these comments for his information.

Cheers
David

David S. MacDougall Partner McInnes Cooper tel +1 (902) 444 8561 | fax +1 (902) 425 6350 Purdy's Wharf Tower II 1969 Upper Water Street, Suite 1300 PO Box 730 Halifax, NS, B3J 2V1 asst Sharon Gates | +1 (902) 454 8778

Notice This communication, including any attachments, is confidential and may be protected by solicitor/client privilege. It is intended only for the person or persons to whom it is addressed. If you have received this e-mail in error, please notify the sender by e-mail or telephone at McInnes Cooper's expense. Avis Les informations contenues dans ce courriel, y compris toute(s) pi?ce(s) jointe(s), sont confidentielles et peuvent faire l'objet d'un privil?ge avocat-client. Les informations sont dirig?es au(x) destinataire(s) seulement. Si vous avez re?u ce courriel par erreur, veuillez en aviser l'exp?diteur par courriel ou par t?l?phone, aux frais de McInnes Cooper.

From: Luciano Lisi [mailto:luciano@cbexplorations.com]
Sent: Wednesday, July 02, 2014 11:01 AM
To: LEFLER, LINDA; Aaron Long; Arden Trenholm (a.trenholm@outlook.com); Austen Hughes; bevan.lock@mcinnescooper.com; Bill Mahody; Bruce Outhouse; Chris Peters; Christine Kavanagh; Daniel Roscoe; David MacDougall; David McLennan; David Regan; Don Regan; ELLIS, BILL; Eva Schmidt; FERGUSON, ERIC; GODBOUT, NICOLE; Holly Bond; Jocelyn Fraser; John Athas; John Woods; Nancy Rondeaux; Nancy Rubin; Paul Lewis; Paul Pynn; Peter Craig; Ron Seftel; Sandy White; Scott McCoombs; John Brereton; Stan Mason; Stephen McGrath; Steve Pronko; RODENHISER, DAVID; Mel Whalen (mci@accesscable.net); sara.mahaney@mcinnescooper.com; sthomas@scotianwindfields.ca
Cc: SUTHERLAND, LAURA; MYATT, LANA
Subject: Re: Renewable to Retail - feedback from Stakeholders

Dear Linda Lefler,

following the first stakeholder session, here are some comments/suggestions:
1) Optimize the time frame to the best of your abilities: the current schedule is way too long.
2) Enable phased in approach so that those projects that are ready to go can start even in advance
of a "Distribution OADT"; i.e. projects that do not use NSPI's system at all.
3) Devote a larger percentage of effort to the "Distribution OADT" then to revising the OATT in order to
optimize as in item 1 above.
4) Employ and improve current Distribution level practices i.e.; IR, Contracts; 2 way metering etc. , just factor
in everything except "energy generation" and that should get you an overall OADT. In other words adopt a common sense
approach that will enable and facilitate.
5) While the OATT had very limited appeal because the tariffs are in effect artificially kept low for Transmission Connected
Customers be prepared for a much larger uptake on the OADT.

All the best,

Luciano Lisi
President
Cape Breton Explorations Ltd.
11 Eleventh Street
Glace Bay, NS Canada B1A 4M3
Tel: 902 849 8520
Tel: 516 515 4849 Cell: 902 537 1159
Skype: lucianolisi
Web: www.capebretonexplorations.com

NS Power Response to Stakeholder feedback on Terms of Reference

1. Recommendation:

Consider a staged approach for retail market access.

Both Port Hawkesbury Paper and Cape Breton Explorations suggested a phased approach though focused on different aspects. PHP suggested that Transmission connected customers could access the retail market earlier based on the assumption that the existing OATT could be leveraged. CBEx suggested expediting retail market access for projects with generation connected behind the NSPI meter and also recommended focusing greater effort on development of the Distribution Open Access Tariff.

Response:

The components of all tariffs and market structures are interdependent and should be developed in an integrated manner. The present schedule allows for iterative development of Strawmen models and responses from stakeholders, as well as one comprehensive UARB application and decision process. Moving forward with a staged approach risks rework and delay as tariffs and processes may need to be revised upon completion of the entire project and stakeholders engage at different stages of the process. As opportunities present themselves for expediting certain mechanisms during the process they will be considered.

2. Recommendation:

Expedite definition of “no negative impact” on existing NS Power customers.

Response:

This recommendation is applicable to all cost recovery matters including the tariffs, rules and procedures that will be developed for Renewable to Retail access and “Stranded” or “Embedded” cost recovery. NS Power agrees that this is a fundamental component of the process and will make the strawman assessing this issue one of the first to be developed for discussion at the next Stakeholder conference.

3. Recommendation:

Specific consideration should be given to the issue of market aggregation.

Response:

This has been added to the Terms of Reference, in Section 3b.

4. Recommendation:

Optimize the time frame; current schedule is too long.

Response:

The schedule was constructed to allow for strawman creation by NS Power, and iterative consultation with all Stakeholders as a means to promote consensus on key matters. The schedule recognizes that other electricity related activities draw on stakeholder time, such as the IRP. We will look for opportunities to tighten the time line.

5. Recommendation:

Employ and improve current Distribution level practices i.e. IR, Contracts; 2 way metering etc.

Response:

The Terms of Reference state that existing NSPSO market mechanisms and systems will be leveraged to the extent possible in the implementation (i.e. by leveraging existing OATT infrastructure and processes, where applicable). The distribution tariff design undertaken in this process will include determining the services that are needed and their prices. Where possible to avoid duplication of effort, existing mechanisms will be used or modified.

6. Recommendation:

Be prepared for a much larger uptake on the OADT.

Response:

The Terms of Reference state that the market administration solution will seek scalability in its implementation, to respond to market uptake. Scalability is necessary as this is our first experience in Nova Scotia with Renewable to Retail competition, and the uptake will be unknown until participants are operating in the competitive market.

July 11, 2014

Renewable to Retail Market Opening

Terms of Reference

1) Objective

To develop and implement a framework in Nova Scotia for competitive renewable electricity supply to retail customers, as directed by the Electricity Reform Act (2013), in alignment with the Province's timelines.

2) Introduction

The NS Electricity Reform Act was enacted on December 12, 2013. The Act enables NS Power's retail customers to purchase renewable low-impact electricity generated in Nova Scotia from any licensed competitive supplier.

The Act stipulates that NS Power shall develop in consultation with stakeholders, and file with the Board for approval, any new or amended tariffs, procedures and standards of conduct that are necessary to facilitate the purchase of renewable low-impact energy.

The Regulations will provide the date by which NS Power will submit its application to the Utility and Review Board.

3) Approach

In support of the development and implementation of the NS renewable to retail market, NS Power will:

a) Consult and collaborate with stakeholders to gain and share knowledge and experience with market structures and systems;
b) Consider successful approaches used in other jurisdictions with active retail markets, including the role of market aggregation;
c) Develop and circulate Strawmen to stakeholders for comment on significant issues or opportunities.
d) Consider potential capital or operating expenditures required by NS Power to support the market opening, including infrastructure, metering, billing, and other system modifications;
e) Create drafts of documentation for review and input of stakeholders;
f) Convene technical conferences throughout the process;
g) Prepare and file UARB application; and

h) Implement required changes based upon the UARB decision.

4) Scope

As set out in section 3G(1) of the Electricity Reform Act (2013), NS Power is directed to develop in consultation with stakeholders, and file with the Board for approval, any new or amended tariffs, procedures and standards of conduct that are necessary to facilitate the purchase of renewable low-impact energy including:

a) a new or amended open access transmission tariff (OATT);
b) a distribution tariff;
c) a new or amended backup/top-up service tariff;
d) a new or amended non-dispatchable supplier spill tariff;
e) new or amended interconnection procedures;
f) new or amended market rules; and
g) any other tariffs, procedures or standards of conduct prescribed by the regulations or that the Board requires Nova Scotia Power Incorporated to develop or amend in order to facilitate the purchase of renewable low-impact electricity.

5) Consultation Framework

NS Power will seek stakeholder input throughout the process, and will schedule stakeholder sessions to facilitate direct stakeholder input.

A timeline for meetings and filings is provided below for the consultation process. It is intended that this will enable establishment of consensus on issues in an efficient manner, anticipating a filing with the UARB in the third quarter of 2015.

6) Criteria

The solution shall be guided by the following criteria:

a) Customers of NSPI and persons who are independent power producers or hold feed-in tariff approvals are not to be negatively affected if some retail customers choose to purchase renewable low-impact electricity from a retail supplier.
b) Retail suppliers and their customers are to be responsible for all costs related to the provision of service by retail suppliers to their customers that would otherwise be the responsibility of NS Power and its customers.
c) Existing NSPSO market mechanisms and systems will be leveraged to the extent possible in the implementation, i.e. by leveraging existing OATT infrastructure and processes, where applicable.

d) The market administration solution will seek scalability in its implementation, to respond to market uptake.

7) Timeline Summary

a)	Stakeholder meeting #1	Q2 2014
b)	Develop initial strawman models	Q3 2014
c)	Stakeholder meeting #2	Q3 2014
d)	Incorporate stakeholder feedback	Q4 2014
e)	Stakeholder meeting #3	Q4 2014
f)	Complete proposed new or amended Tariffs*	Q2 2015
g)	New or amended Tariffs, Procedures, etc. filed with UARB	Q3 2015
h)	NS Power implementation complete; organizational readiness	Q2 2016

*Note: Additional stakeholder consultation as required

Nova Scotia POWER
An Emera Company

JUNE 17, 2014

Stakeholder Engagement Process

Renewable to Retail Market Opening

Stakeholder Conference Agenda
June 17 – Halifax Marriott Harbourfront

Welcome	9:00	
1. Introductions (Nicole Godbout)	9:00- 9:15	15 min.
2. Background information - legislation, regulations (NSDOE)	9:15 - 9:45	30 min.
3. Process for Stakeholder Engagement (NG)	9:45 - 10:15	30 min.
4. Review proposed Terms of Reference (NG)	10:15 - 10:45	30 min.
Break	10:45 - 11:00	15 min.
5. Background on Markets and Open Access (Bill Ellis with Voytek Grus and John Charlton) o NS Wholesale market/OATT/GIP o Tariffs (BU, TU, Spill) o New Distribution Tariff	11:00 – 12:00	60 min.
6. Wrap-up/consolidate (NG/BE)	12:00 - 13:00	60 min. or less

Nova Scotia POWER
An Emera Company

Stakeholder engagement

Objective

Provide a transparent and efficient process to gain input from those interested in the forthcoming Renewable to Retail Market opening, and use that input to help create tariffs, procedures and standards of conduct that are responsive to stakeholder priorities within the parameters established by the Electricity Reform (2013) Act.

Stakeholder engagement

Engagement will follow the same model used successfully in recent regulatory matters

(Cost of Service, Generator Interconnection Procedures).

Nova Scotia POWER An Emera Company

Stakeholder engagement

Method of Engagement

- Establish Terms of Reference and engagement process
  - Incorporating market principles contained in the Act

Nova Scotia POWER An Emera Company

Stakeholder engagement

Method of Engagement

- "Strawmen" will be developed for each significant issue or opportunity
  - New/Amended Market Rules,
  - OATT Changes,
  - New Distribution Tariff,
  - GIP changes,
  - Backup, Top-up and Spill Tariff changes,
  - Stranded Cost Recovery,
  - Others as required.

Nova Scotia POWER An Emera Company

Stakeholder engagement

Method of Engagement

- Quarterly technical conferences (Live & WebEx) to gain feedback
  - 2014: June 17, September, December
  - 2015: 1st quarter – if required
- A website will contain information from Stakeholder conferences and other interactions

Nova Scotia POWER An Emera Company

Progress Update

- UARB Notice of Filing and advertising for participants complete
- Draft Terms of Reference developed
- 1st Stakeholder Conference underway (today)

Nova Scotia POWER An Emera Company

Project Schedule - Update

- Initiate NSUARB process……………………………………………April 2014
- Begin NSPI research and concept development………….End Q2 2014
- Stakeholder meeting #1………………………………………..June 2014
- Incorporate stakeholder feedback…………………………….End Q3 2014
- Stakeholder consultation #2…………………………………….End Sept 2104
- Incorporate stakeholder feedback …………………………….End Q4 2014
- Stakeholder consultation #3 ……………………………………Dec 2014
- Complete proposed new or amended Tariffs*……………..Late Q2 2015
- New or amended Tariffs filed with UARB……………………Early Q3 2015**
- UARB approval of new and amended tariffs………………..Q1 2016
- NS Power implementation complete; organizational readiness…………………………………………………………………Late Q2 2016
  - ***Additional stakeholder consultation as required**
  - **** Or as directed by the Regulations**

Nova Scotia POWER
An Emera Company

Terms of Reference

- See attachment

Nova Scotia
POWER
An Emera Company

TUESDAY, JUNE 17, 2014

Renewable to Retail Market Opening

NS Power's Role – from the Electricity Act (2013)

Develop any changes to tariffs, procedures or standards of conduct in consultation with stakeholders and file with the UARB:

1) a new or amended Open Access Transmission Tariff
2) a distribution tariff
3) a new or amended Backup/Top-up Service Tariff
4) a new or amended Non-dispatchable Supplier Spill Tariff
5) new or amended interconnection procedures
7) new or amended market rules
8) any other tariffs, procedures and standards prescribed by regulations or required by the UARB

Nova Scotia POWER An Emera Company

The NS Electricity Market Today

- Currently two markets in NS:

1. A regulated retail market; and
2. A competitive wholesale market
   - Eligible customers may arrange bilateral transactions with a supplier, or suppliers for all or part of their energy needs.
   - Suppliers may be located inside or outside of Nova Scotia.
   - Wholesale Market supported by a UARB-approved, cost-based, Open Access Transmission Tariff (OATT).
   - Wholesale Market Rules identify the rights and obligations of the market participants

Open Access Transmission Tariff - OATT

- Provides procedures and agreements to obtain non-discriminatory access to NSPI's Transmission System.
- Defines the transmission access services offered and the costs for each service.
- Includes Generator Interconnection Procedures (GIP) defining the processes to interconnect a generating facility to the NSPI Transmission System.

Nova Scotia POWER
An Emera Company

Nova Scotia Wholesale Electricity Market

- Allows eligible buyers and sellers to enter into bilateral transactions for the purchase and sale of electricity and related services.
- Eligibility for Market participation has been defined in the Legislation and Regulations and in the Transmission Tariff:
  - Nova Scotia Power Incorporated, the electric utilities of the towns of Antigonish, Berwick, Canso, Lunenburg and Mahone Bay and Riverport.

Nova Scotia POWER An Emera Company

Nova Scotia POWER
An Emera Company

TUESDAY, JUNE 17, 2014

Backup / Top-up & Spill Service Tariffs

Backup Service

- Provides energy during times when the supplier is unable to deliver due to maintenance or unplanned equipment failure.
- Will be required to replace supply from both dispatchable and non-dispatchable generation sources.
- Can be obtained from NS Power, another supplier, or it can be self-supplied.
- Backup service must be accounted for in the schedule provided to the NSP System Operator.
- OATT imbalance charges apply to any unscheduled energy required in addition to scheduled backup.

Top-Up Service

- Non-dispatchable generation varies from customer load.
- When this generation is less than the customer's contracted requirement some other dispatchable generation source is required to "top-up" the non-dispatchable generator so that customer load continues to be fully served.
- Top-up service applies to the varying amount of energy required to top-up the difference between the customer's contracted load and the primary supplier's actual output.
- Top-up service must be accounted for in the schedule provided to the NSP System Operator.
- OATT imbalance charges apply to any unscheduled energy required in addition to scheduled top-up.

BU,TU - Charges

BUTU charges have three components:

- **Administration Charge**
- **Demand Charge**: Based on kW of Billing Demand measured on average hourly basis
- **Energy Charge**: Average annual marginal energy cost as approved for GRLF rate

Nova Scotia POWER
An Emera Company

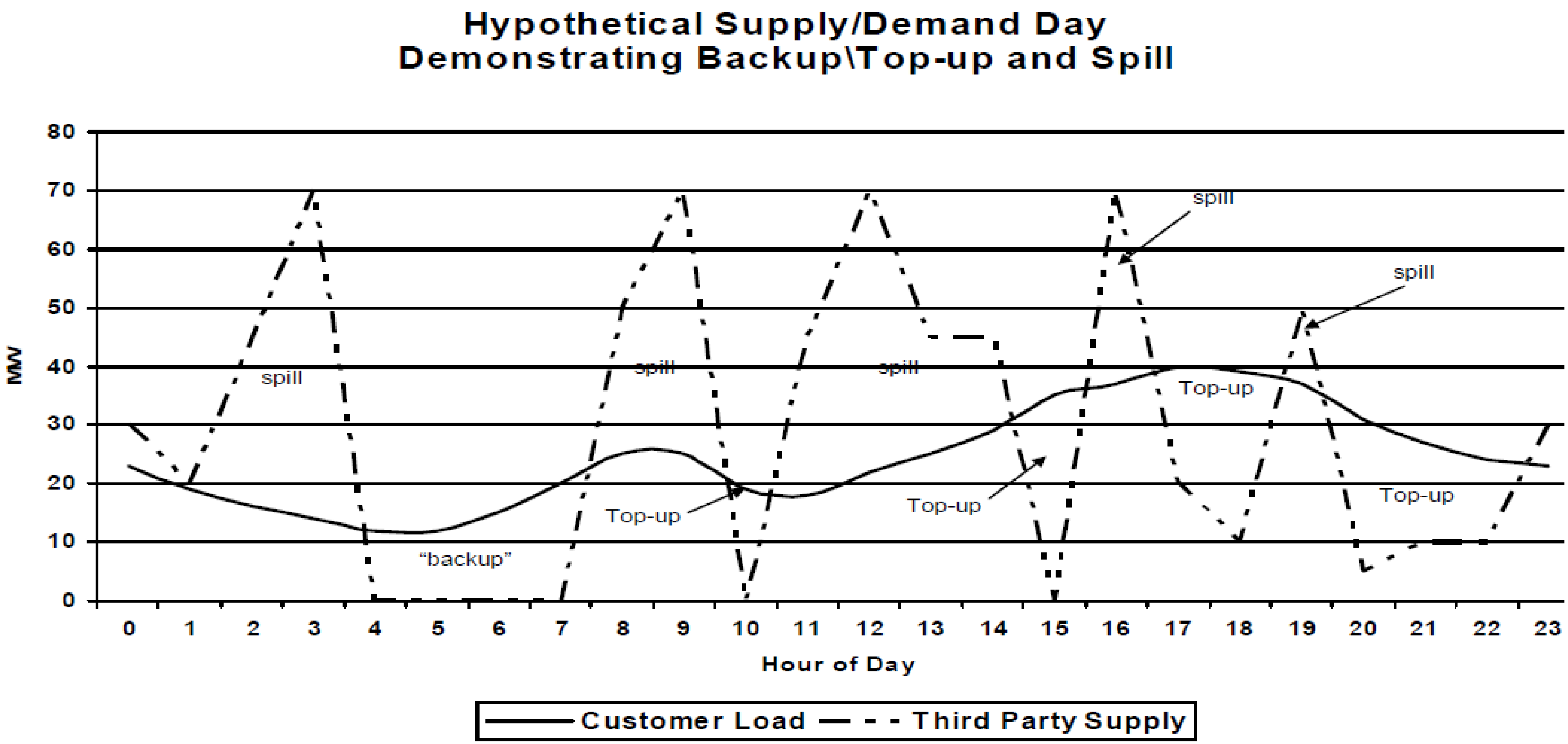
Spill Service

- Non-dispatchable generation may at times exceed its contracted customer demand.
- Energy produced by the third party generator that exceeds its customer load in any hour is referred to as "spill".
- The spill tariff facilitates NS Power's purchase of certain amounts of this excess energy, if and when such energy is produced.
- Spill energy must be accounted for in the schedule provided to the System Operator.

Spill - Charges

Spill charges have two components:

- **Administration Charge**
- **Energy Credit**: Compensated at the Company's forecast average annual marginal energy costs as approved for use with the GRLF rate.


Hypothetical Supply/Demand Day
Demonstrating Backup\Top-up and Spill
80
70
60
50
40
30
20
10
0
MW
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour of Day
spill
spill
spill
spill
spill
Top-up
Top-up
Top-up
Top-up
"backup"
Customer Load
Third Party Supply

Distribution Tariff

- Defines the terms and conditions under which the distribution access service are offered
- Defines the charge(s) for providing system access.

Distribution Tariff Design Considerations

- Cost of Service based
  - Differentiated by customer class
- Postage stamp based
- Items to Consider
  - Customer metering requirements
  - Retail customer service transactions
    - » Billing
    - » Outage management

Nova Scotia POWER
An Emera Company

Distribution Tariff – examples from other jurisdictions

- Fully Unbundled Jurisdictions
  - Alberta, Ontario, Texas
- Partially Unbundled Jurisdictions
  - California

Nova Scotia POWER
An Emera Company

Nova Scotia POWER
An Emera Company

TUESDAY, JUNE 17, 2014

NS Power Generator Interconnection Procedures

Generator Interconnections

Transmission Connected (69 kV and above)	Distribution Connected (Below 69 kV – typically 25kV and below)	
Any Capacity **Generator Interconnection Procedures (GIP)**	*Over 100 kW* **Class 2 Distribution Interconnection Procedures (DGIP)**	*Under 100 kW* **Class 1 Interconnection Guideline**

Nova Scotia POWER An Emera Company

Generator Interconnection Procedures

- Allows non-discriminatory access to NS Power transmission system (69kV or above) while protecting reliability
- Interconnection Queue, system study procedures, and standard Interconnection Agreement templates
- Access is based on "First ready, first served" model

Nova Scotia POWER An Emera Company

Queuing Principles

- Public posting of Queue on OASIS showing positions
- Advanced Queue position is attained only after defined readiness progression milestones are met
- Queue position can only be transferred to another entity if the Generating Facility is acquired

Nova Scotia POWER An Emera Company

GIP – Progression Milestones

- Provision of:
  - Any one of the following:
    - Executed contract for sale of energy (>50% capacity)
    - Long-term transmission service reservation (1yr > 50% capacity)
    - Approval by the NSUARB for the Generating Facility expenditures
    - The project’s energy/capacity has been identified as being required to meet demand, reliability or Renewable Electricity Standard requirements by a load serving entity.

Nova Scotia POWER An Emera Company

Distribution Generator Interconnection Procedures

- The DGIP accommodates IPP access to the NS Power distribution system for sale of energy to NS Power via PPA, COMFIT, or net metering.
- Currently it does not accommodate direct to retail sales from IPPs.
- It does not include use of the transmission system or permit transmission system impacts.
- Total generation is typically limited to minimum distribution substation load.

Nova Scotia POWER An Emera Company

Next steps

- Comments on Terms of Reference from Interested Parties – requested by July 2
- Terms of Reference finalized and issued to Interested Parties – July 11
- General comments from Interested Parties on areas of interest/considerations for NS Power in development of Strawmen – requested by July 15
- NS Power development of draft Strawmen positions – over summer
- Second Stakeholder conference – early Fall (date TBC)

Electricity Act Amendments

Renewable to Retail Market Opening

Scott McCoombs

Director, Nova Scotia Department of Energy

NOVA SCOTIA

New Legislative Provisions

- Permits the sale of renewable low-impact electricity generated within the province between a retail customer and a retail supplier
  - Retail supplier excludes NSPI and municipal utilities
  - Retail customer excludes customers municipal utilities
- Establishes licensing requirement for retail suppliers (exclusions permitted in regulations)
- Directs the development of necessary tariffs, procedures and standards of conduct for UARB approval

Tariffs, procedures and standards of conduct

- open access transmission tariff;
- distribution tariff;
- backup/top-up service tariff;
- non-dispatchable supplier spill tariff;
- interconnection procedures;
- market rules; and
- others required by UARB or regulations

A Few Guiding Principles

- NSPI retains obligation to serve
- NSPI customers and existing independent power producers or feed-in tariff approval holders are not to be negatively affected if some retail customers choose to purchase from a retail supplier
- Retail suppliers and their customers are to be responsible for all costs related to the provision of service by retail suppliers to their customers

NOVA SCOTIA

Regulations by Province

- Establish key dates
  - Deadline for application to UARB for approval of tariffs, procedures and standards of conduct
  - Start date for renewable to retail sales
- Deem certain retail suppliers to be public utilities
- Relieve certain retail suppliers of requirement for retail supplier license
- Require development and approval of additional tariffs, procedures and standards of conduct

NOVA SCOTIA

Regulations by Board

- Application process for a retail supplier license
- Terms and conditions of a retail supplier license
- Amendment, suspension, reinstatement or cancellation of a retail supplier license
- Transfer or assignment of a retail supplier license
- Establish fees

Nova Scotia POWER
An Emera Company

OCTOBER 9, 2014

Stakeholder Session #2

Renewable to Retail Market Opening
Distribution Service Tariff

Distribution Service Tariff

- The Distribution Service Tariff provides:
  - The terms and conditions for obtaining non-discriminatory access to NS Power’s distribution system and services
  - Procedures for obtaining service
  - Standard form service agreements
  - Charge(s) for providing distribution access service.
- Distribution service tariff enables:
  - Connection to the distribution system by RtR customers
  - Delivery of electricity to the RtR Customer through the distribution system
  - Customer Service transactions with the RtR Customer (switching, metering, billing, outage response, service quality, etc.)

Distribution Service

- NS Power will own, control, and operate the distribution facilities used for the delivery of electricity and provision of distribution service under this Tariff.
- The Licensed Retail Supplier (LRS) is responsible for providing the total energy and capacity required by the RtR Customer during any given billing period.

Common Distribution Tariff Charges

- **Customer Service Charge:** A fixed monthly charge to recover the costs associated with meter reading, billing, customer service and account maintenance, and general utility operations.
- **Distribution Charge**: A variable charge to recover the cost of building and maintaining the distribution system, including overhead and underground distribution lines, poles, and distribution substations.
- **Line Losses**
  An adjustment made on the basis of the electricity consumed to account for losses incurred during delivery through the distribution system.

Nova Scotia POWER An Emera Company

Market Participants

- Low Impact Renewable Electricity Generators
  - Connect to the NS Power grid and deliver electricity to the RtR Market.
- Licenced Retail Suppliers (LRS)
  - Purchase low impact renewable electricity, will sell to retail loads (RtR Customers) in Nova Scotia.
- RtR Customers
  - Contract with Licenced Retail Suppliers for electricity and will continue to be NS Power customers for delivery of services.
- NS Power
  - Administer the RtR market and provide OATT and Distribution Service Tariff services

Tariff Content

The Distribution Service Tariff may specify:

- RtR Customer notice requirements for switching between LRS's and/or NS Power bundled service (consistent with licensing requirements)
- Minimum service durations before switching
- Procedures for RtR Customer moves
- Financial security procedures for the RtR Customer and LRS
- Invoicing responsibilities and processes
- Non-payment and disconnection processes, rights and responsibilities

Metering

- The Distribution Service tariff will address:
  - Meter ownership, reading and billing responsibilities
  - Meter technology/communication requirements (interval metering)
  - Exchange of metering information to/from LRS
  - Metering/billing dispute procedures

Ancillary Services/Losses

- Ancillary services are required to support both Transmission and Distribution Service to maintain reliability.
- Ancillary Services will be provided under the terms and conditions of the OATT.

- Real power losses are associated with distribution service.
- The RtR customer is responsible for costs associated with distribution system losses.
- Distribution loss factors will be determined by NSP

Nova Scotia POWER An Emera Company

Next Steps

- Please provide comments on today's presentation by October 23, 2014
- As we develop consensus around market models, next steps with respect to a distribution tariff will be determined.
- If the development of a distribution tariff is necessary, the Company will present a proposal for stakeholder consideration.

Nova Scotia POWER
An Emera Company

OCTOBER 9, 2014

Stakeholder Session #2

Renewable to Retail Market Opening
Embedded Cost Recovery

Embedded Cost Recovery in the Renewable to Retail Market

- The Electricity Reform Act requires that costs attributable to customers who choose an alternate retail electricity supplier must be borne by those customers or their retail suppliers, and not the customers who remain with the utility.
- This necessitates consideration of recovery of embedded costs in the development of tariffs and charges for the RtR market.

Market Models and ECR

- The market design approaces, i.e. Disaggregated vs Integrated, offer options for ECR:
  - A disaggregated approach would require an Embedded Cost Recovery Mechanism.
  - An integrated approach avoids separate embedded cost recovery - the costs stranded by a retail customer exit continue to be included in the integrated RtR service tariff.

Costs Included in ECR

- Two areas of cost recovery are affected by customer departure:

  1. Capital costs: e.g. generation plant
  2. Deferred costs: Costs incurred in the delivery of past services whose recovery has been deferred. E.g. Fuel Adjustment Mechanism deferral.

- For the purpose of this presentation, "Embedded Costs" refer to both Deferred and Capital costs.

Nova Scotia POWER
An Emera Company

Potential Approach to Embedded Cost Recovery

- Deferred Cost Recovery
  - A pro rata amount to be paid by a departing customer.

- Capital Related Cost Recovery

  Determined using a FERC-based lost revenue approach, recovered through one of the following options:
  - Lump sum payment of the entire amount
  - Amortization of the lump sum amount over 5 years through application of a monthly fee
  - Surcharge on the customer's transmission rate in $/kW determined as a ratio of nominal lump sum amount and expected total monthly KW usage in the next 5 years.

Nova Scotia POWER An Emera Company

Conclusion

- Please provide comments on today's presentation by October 23, 2014
- As we develop consensus around market models, next steps with respect to ECR will be determined.
- If the development of an ECR mechanism is necessary, the Company will present a proposal for stakeholder consideration.

Nova Scotia Power
Renewable to Retail Project
Market Design White Paper

Robert Cary & Associates Inc.

October, 2014

Structure of presentation

- Part 1: overview (white paper sections 1 & 2.1)
  - *Approach to the task, and criteria for success*
  - *Criteria for selection among options*
    - *Clarification questions*
- Part 2: options
  - *Review of the options (white paper section 2.2 to 2.5)*
  - *Review of the conclusions (white paper section 3)*
    - *Clarification questions*
    - *Initial feedback*
- Part 3: design aspects (white paper sections 4 to 7)
  - *Metering and settlement*
  - *Avoided cost & Embedded Cost Recovery*
  - *Connection issues*
  - *Other issues*
    - *Clarification questions*
    - *Initial feedback*

Approach to the task

- The basis of the white paper is:
  - *Firm boundaries provided by the legislation*
  - *Project terms of reference*

- Project success depends on inputs from several parties:
  - *Potential investors and participants are responsible to market, invest and operate, and more immediately to contribute to design*
  - *The NS UARB has general oversight of rates and regulations*
  - *The NS UARB is responsible to develop a licencing framework that will act in concert with the market framework*
  - *NS Power success is to provide the framework that enables the market to develop:*
    - *as provided in legislation and regulations*
    - *in accordance with the timing set out therein*
    - *in a way that will meet stakeholder needs*

Working assumptions - 1

- The Renewable to Retail supply chain will comprise:
  - *The low impact renewable generation owner/operator*
    - *will have an interconnection agreement with NS Power*
    - *will inject null electricity from that renewable generation to NS Power.*
  - *The Licenced Retail Supplier (LRS)*
    - *will buy from generator and sell to customers*
    - *relationship with NS Power will depend on the option selected.*
  - *The RtR customer*
    - *will buy electricity from the LRS and*
    - *delivery service from NS Power (subject to option selected)*
  - *The generation owner / operator may be the same as the LRS (subject to any licencing provisions)*

Working assumptions - 2

- The compliance obligation on an LRS is expected to be
  - *In each compliance period it purchases or generates at least as much low impact renewable generation as it sells to its RtR customers*
    - *with adjustment for losses.*
  - *No aspect of the renewable nature of the electricity generated to meet this compliance obligation may be used for any purpose other than this program.*
  - *The actual compliance period remains to be determined*
    - *assumed at this stage to be one calendar year.*

Developing the criteria

- All options must satisfy the legislation and fulfil the project terms of reference
- After that, I have suggested some supplementary criteria to choose among options. Project success is most likely if the market framework provides:
  - *Simple and readily comprehensible solutions;*
  - *Simplicity of implementation;*
  - *Predictability of outcomes (for NS Power, for generators / Licenced Retail Suppliers, and for customers); and*
  - *The minimum practical regulatory or administrative burden.*
- We seek stakeholder input on these and any additional considerations
- Only users can provide the user perspective, so your inputs are essential to success

What are the options?

- Physical options
  - *Disaggregated*
  - *Integrated*
  - *Hybrid*

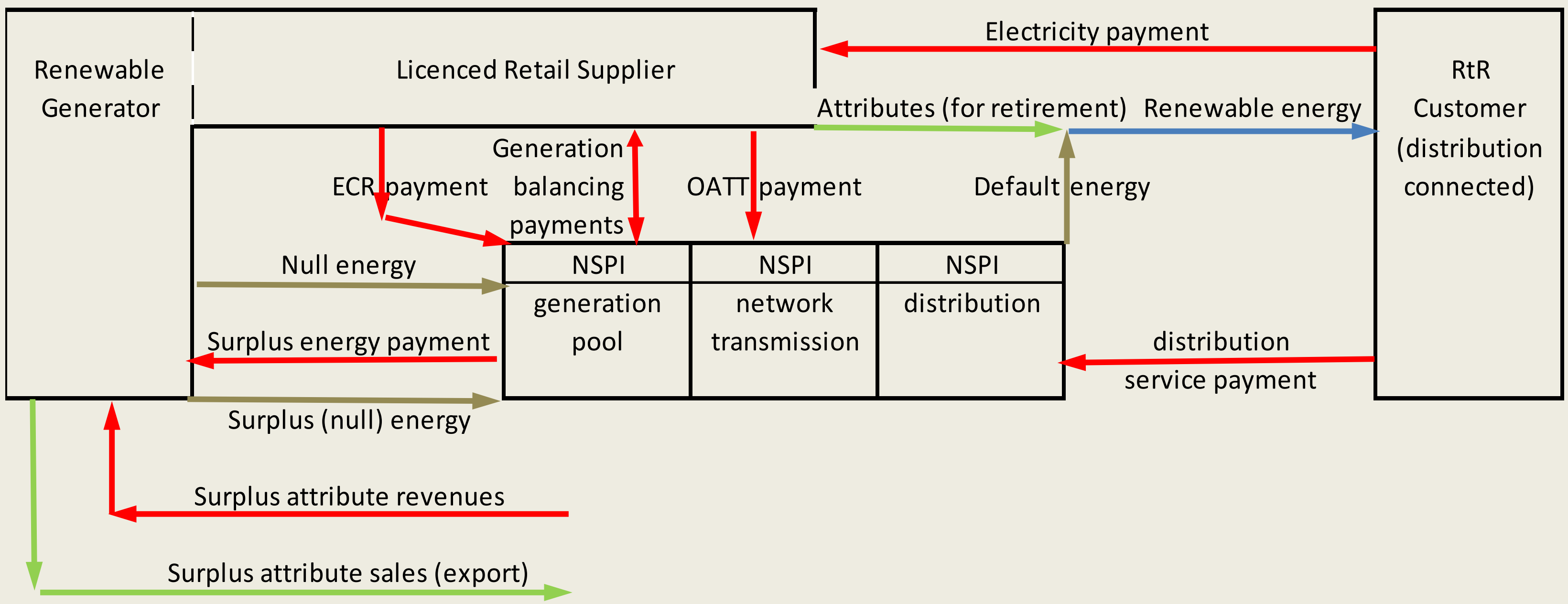
- Financial option
  - *Metered sub-option*
  - *Block sub-option*

Disaggregated option principles

- Separate tariff for each step of the way. Working back from the customer
  - *Distribution service tariff (payable by customer)*
  - *All customer loads aggregated for application of OATT (LRS is the transmission customer) **
  - *Top-up charges to provide load when renewable generation resource is not generating enough **
  - *Spill & imbalance payments to absorb energy generated, mismatched to load **
  - *Surplus energy payment in respect of energy generated in excess of [annual] RtR customer load*
  - *Capacity backup tariff to pay for capacity required to provide top-up energy and meet system reserve requirements (in addition to effective self-provided capacity)*
  - *ECR for any assets stranded*
- Items marked with " * " require hourly quantity calculations measured or inferred from customer meters.
- This option maximises the proportion of total cost that a customer pays to LRS, who then settles with NS Power for all services except distribution

Disaggregated option chart

Figure 1
Disaggregated option; energy and cash flows

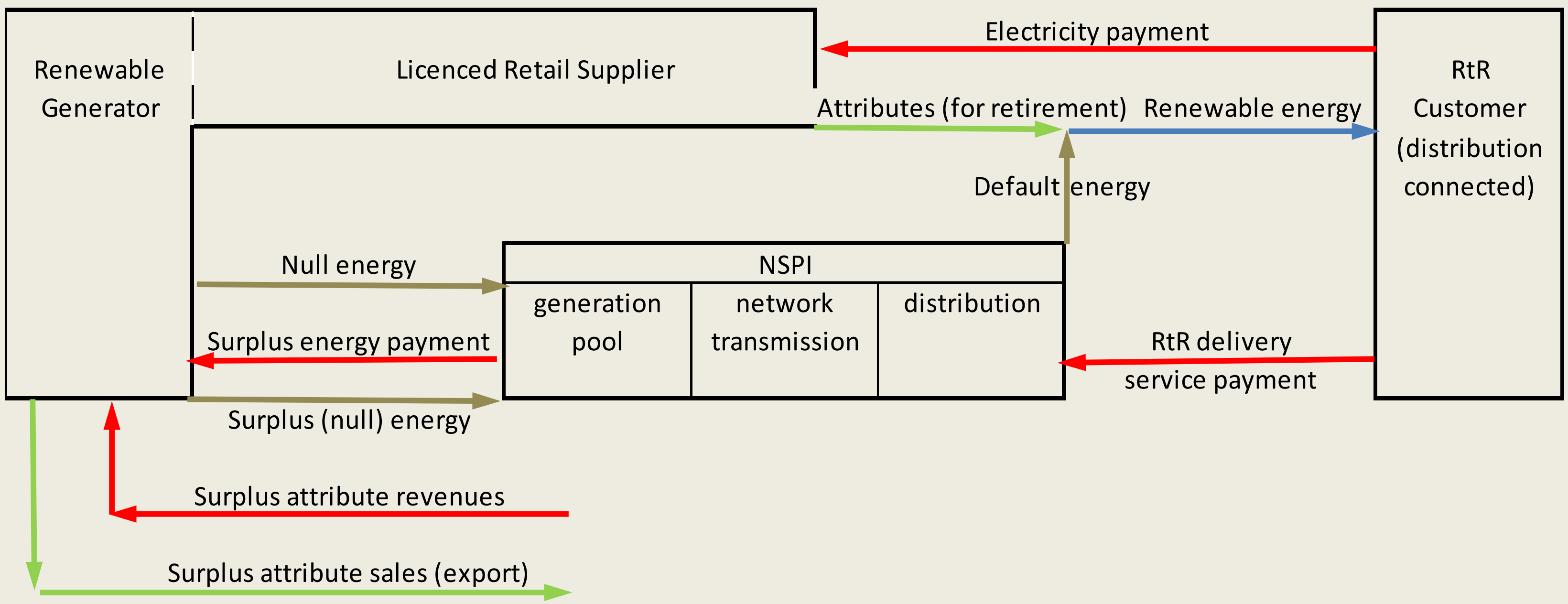


Integrated option principles

- A single integrated delivery service tariff payable by the customer covers all of the above elements except for annual surplus energy.
- The basis of this tariff is the existing NS Power full service tariff applicable to customer class less the net generation cost that is avoided by the injection from the renewable resource.
- In addition, NS Power pays the generator for annual surplus energy injected to the grid, at a rate based on the avoided cost.

integrated option chart

Figure 2
Integrated RtR tariff option; energy and cash flows

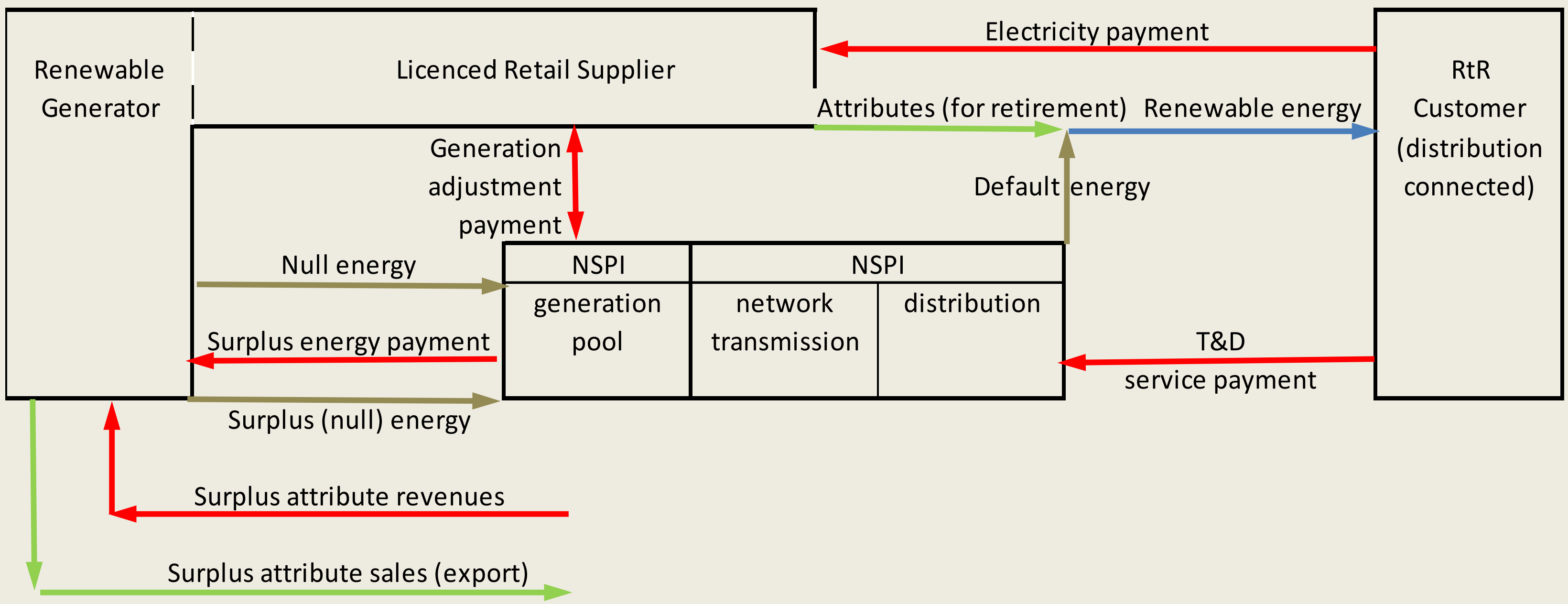


Hybrid option principles

- Compromise between disaggregated and integrated
- Delivery, comprising transmission and distribution, is treated as a single tariff developed specifically for this purpose, and charged to the customer on the basis of customer metering
  - *Probably uses the same customer classes as NS Power full service*
- All of the generation-related services covered by a separate tariff developed for this purpose and charged to the generator / LRS
- In addition, NS Power pays the generator for annual surplus energy injected to the grid, at a rate based on the avoided cost.

Hybrid option chart

Figure 3
Hybrid option; energy and cash flows

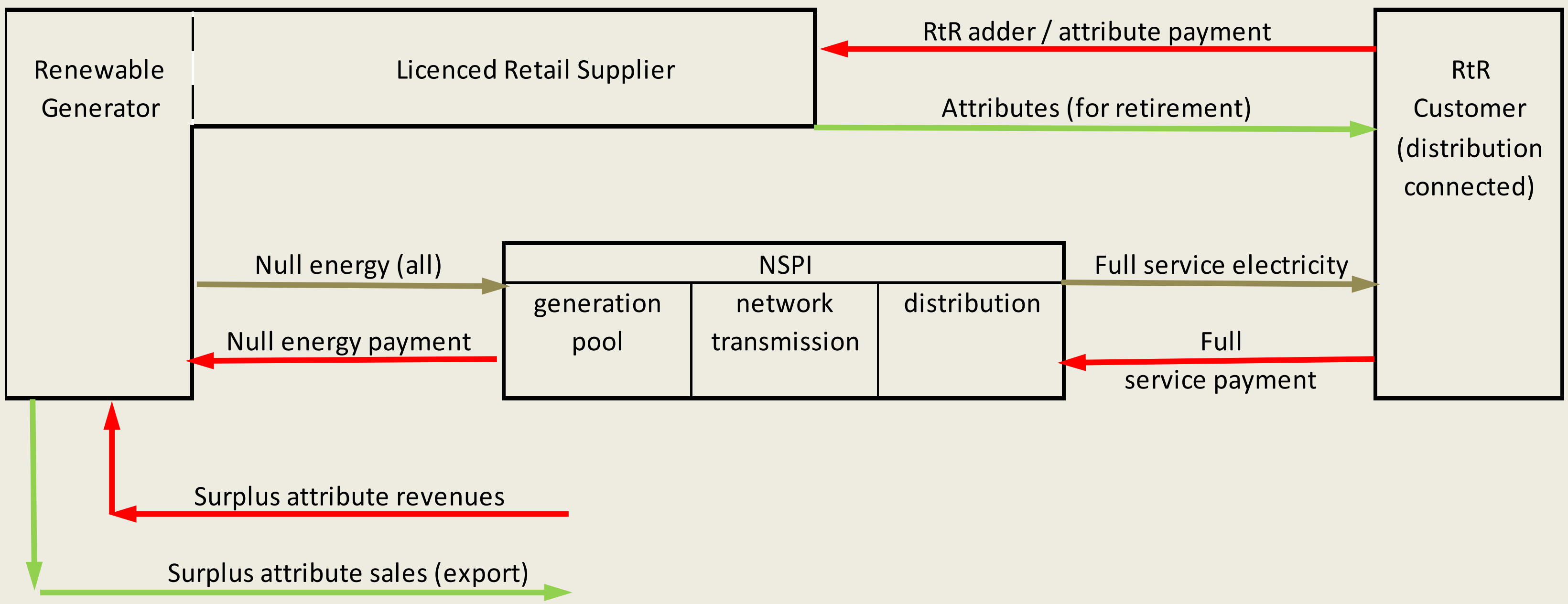


Financial option principles

- Quite a different approach from a marketing perspective
- Much the simplest from an implementation perspective
- Customer pays NS Power for all energy at the applicable full service tariff
- Customer pays LRS for attributes
- Either:
  - *Predetermined kWh quantity per month, or*
  - *Metered kWh quantity per month*

Financial option chart

Figure 4
Financial market option; energy and cash flows



Comparison table: cost allocation

Nova Scotia Renewable to Retail market design

Principal options comparison table: sheet 1, cost allocation

Description	Disaggregated tariffs	Integrated RtR delivery services	Hybrid option	Financial market option
Cost Allocation				
Distribution costs	paid by customer under a new distribution service tariff	paid by customer as part of integrated delivery tariff	paid by customer as part of delivery tariff	paid by customer as part of full service tariff
Transmission costs	paid by LRS under OATT provisions based on aggregated load / inferred hourly load profile LRS recovers under electricity price	paid by customer as part of integrated delivery tariff	paid by customer as part of delivery tariff	paid by customer as part of full service tariff
Generation balancing services	paid by LRS under backup / top-up tariff and credit under spill tariff based on aggregated load / inferred hourly load profile LRS recovers under electricity price	paid by customer as part of integrated delivery tariff	paid by LRS under generation adjustment payment LRS recovers under electricity price	paid by customer as part of full service tariff
Avoided NSPI fuel costs on RtR sales	not applicable	credited to customer in determining integrated delivery tariff	not applicable	none
Avoided NSPI capacity costs on RtR sales	not directly applicable may need recognition	credited to customer in determining integrated delivery tariff	credited to LRS under generation adjustment payment LRS may recognise in determining electricity price	credited to generator as part of renewable injection tariff
Surplus electricity (annual basis)	credited to LRS / Generator under surplus spill tariff	credited to LRS / Generator under surplus spill tariff	credited to LRS / Generator under surplus spill tariff	credited to generator as part of renewable injection tariff
Embedded Cost Recovery	requires separate determination	implicit in delivery tariff avoided cost calculation	implicit in generation adjustment payment calculation	none required

Comparison table: tariff structure

Nova Scotia Renewable to Retail market design

Principal options comparison table: sheet 2, tariff structure

Description	Disaggregated tariffs	Integrated RtR delivery services	Hybrid option	Financial market option
Tariffs requiring regulatory approval				
Full services tariffs				Unchanged from today
Distribution service	required			
OATT review	required			
T&D service			required	
Top-up and spill service	required			
Backup capacity	required			
Generation adjustment service			required	
Integrated RtR delivery services		based on full service rates minus avoided cost		
Surplus supply (based on avoided cost)	required	required	required	required, in the form of a renewable injection tariff
Embedded Cost Recovery	potentially required			

Comparison table: benefits against criteria

Nova Scotia Renewable to Retail market design

Principal options comparison table: sheet 3, benefits comparison against identified criteria

Description	Disaggregated tariffs	Integrated RtR delivery services	Hybrid option	Financial market option
Criteria				
Legislation compliance				
Supports obligation to serve	yes, subject to detail of ECR design etc	inherently yes	inherently yes	inherently yes
Demonstrable neutral impact on others	needs to be reflected in each element of tariff structure as opposed to globally	inherently yes	yes	inherently yes
Project terms of reference				
scalability	yes	yes	yes	yes
leveraging market mechanisms	yes, with additions required	yes, with limited adjustment	partial	yes
Provisional design objectives				
Simple & readily comprehensible solutions	comprehensible but more challenging	simplest and most transparent of the physical supply options	moderate	simplest in concept
Simple implementation	most complex	simplest of physical options	moderate	simplest
Predictable outcomes	least predictable	most predictable (RtR customer bears avoided cost uncertainty in regulatory rate setting)	somewhat predictable	most predictable (generator bears avoided cost uncertainty in regulatory rate setting)
Minimum regulatory & administrative burden	greatest complexity and burden	lowest among physical market options	moderate	lowest regulatory and administrative burden

Conclusions discussion

- The white paper makes observations based on the comparisons set out in the descriptions and tables.
- There may be trade-offs in order to arrive at the best overall solution.
- The selection of an option depends on the input of potential participants and other stakeholders.
- Clarification questions?
- Initial feedback?

Metering and load profile issues

- Metering requirements
  - *The disaggregated option requires measurement or inference of hourly customer load for:*
    - *OATT charges including imbalance*
    - *Top-up and spill charges*
  - *To the extent hourly consumption is measured, do you need daily polling of meters or monthly / bimonthly download?*
    - *This has settlement timing implications*

- Meter ownership
  - *NS Power*
  - *Licenced Retail Supplier*

- These choices are dependent on option selected
  - *Comments welcome, but discussion therefore deferred*

Collection cash flows etc

- Three options, somewhat dependent on option selected:
  - *Supplier consolidated*
    - *question of who is the distribution customer in this case*
  - *Split (note that this is implicit in the financial market framework)*
  - *NS Power consolidated*
    - *NS Power as collection agent for LRS*

- The white paper uses split billing as the easiest framework in which to describe the tariff options, but without seeking to prejudice the selection.

- Feedback?

Avoided cost

- General
  - *The white paper flags the importance of the avoided cost construct*
  - *The principle is easy, the implementation may not be so easy*
  - *Some considerations at this stage in considering avoided costs*
- Avoided energy costs
  - *We will have to consider issues such as*
    - *determination of avoided cost rates over what period (yearly in advance / seasonal in advance / hourly in retrospect)*
    - *basis for determination of avoided MWh (depending on option selected)*
- Avoided capacity cost
  - *The application depends on the option selected*
  - *Much harder to determine, but always ex ante and based on planning considerations*
  - *The MW quantity is technology specific*
- Feedback request ?

Embedded Cost Recovery

- The other side of the avoided cost coin
- Embedded cost recovery is necessary whenever the application of a particular tariff structure would otherwise omit recovery of costs that are not avoided
  - *Such costs cannot be transferred to other customers*
  - *Must be borne by RtR market participants*
- This is not an issue in the financial market option, or to the extent that tariffs are specifically based on avoided costs
  - *Embedded costs are by their nature not avoided*

Interconnection issues

- Location considerations
  - *Pooled basis with possible consideration of specific transmission loss factors*

- Interconnection procedure
  - *Slight departure in treatment of network upgrade costs so that any such costs are not shifted to other NS Power customers*

- Operational integration
  - *Curtailment similar to others*
  - *The potential issue is curtailment sequencing to avoid harm to other PPA generators*

Other issues

- Comments on issues listed?
- Any other particular look-ahead issues that stakeholders want to identify at this time?

Nova Scotia Power

Renewable to Retail Project

Market Design White Paper

Robert Cary & Associates Inc.

3nd October, 2014

Contents

1 Introduction

This white paper is intended to provide a basis for stakeholder consideration of, and input to, the design of the Renewable to Retail (RtR) electricity[1] market in Nova Scotia. Options remain open at this time, and any proposals contained in this document are those of the consultant and have not in any sense been adopted by Nova Scotia Power.

The white paper focusses on the enabling market framework to be established by Nova Scotia Power (NS Power) in accordance with legislation[2] and regulations established by the Government of Nova Scotia. This framework will be complemented by licencing provisions to be developed and administered by the Nova Scotia Utility and Review Board (Board, UARB). It is envisaged that the participants in the RtR market will comprise:

- Renewable Electricity Generators connected to the NS Power transmission grid directly or through a distribution system in accordance with existing transmission or distribution connection procedures, subject to review of those procedures.
- Licenced Retail Suppliers (LRS) who will purchase renewable electricity from renewable generators sited in Nova Scotia, who will be participants in the NS Power-administered electricity market, and who will sell to retail loads in Nova Scotia in accordance with the provisions of their licence from the Board.
- RtR customers, who will contract with Licenced Retail Suppliers for electricity, and who will continue to be NS Power customers in respect of delivery services.

NS Power proposes to design the market framework to accommodate separate entities as Licenced Retail Suppliers and Renewable Electricity Generators or these functions performed by the same entity. It is the working assumption of this White Paper that a Licenced Retail Supplier would not be permitted to sell in any year[3] more "low impact renewable electricity" to its customers than it had purchased (or generated) from qualifying Nova Scotia resources, and that neither it nor the generator would be permitted to sell to a third party any attributes or offsets in respect of the "renewable electricity" that was sold to RtR customers.

RtR customers may be either distribution-connected or transmission-connected. The costs and rates for the delivery services would be designed in conjunction with the cost of service studies and rates of the corresponding full services.

[1] In this White Paper, references to renewable electricity mean renewable low-impact electricity.
[2] Electricity Reform (2013) Act

[3] Note that using one year for such compliance period has not been established as a standard. One year is however the shortest period which absorbs all seasonal variability in both generation and load profiles, and is the typical period over which rates are expected to recover cost of service. It is thus the natural period to use for compliance and other accounting, recognising that a licencing regime could also incorporate carry-over of attribute surplus or deficiency.

In this white paper, "electricity" is generally used to describe the product provided by the Licenced Retail Supplier to RtR customers, and "delivery services" is used to describe the bundle of services that is provided by NS Power to RtR customers. The split between "electricity" and "delivery services" will depend on the market design framework as discussed below, noting that the final stage distribution service will always be part of the delivery service package.

The balance of this white paper is organised as follows:

- Section 2 sets out the criteria used in the development of alternative models, and then provides descriptions of the alternative models that have been developed for consideration.
- Section 3 provides a tabulated comparison of some of the key features of the alternative models and how they measure up to the criteria used in their development.
- Subsequent sections develop the discussion of issues that will be of concern in the development of most alternative models:
    - Metering and settlement;
    - Avoided cost and embedded cost;
    - Connection and related issues; and
    - Other design issues identified to date.

Each section identifies certain questions for the consideration of stakeholders, without seeking to limit the discussion in any way.

2 Market Design Options

2.1 Criteria for option design and selection

Any market design options must meet the legislative requirements that can be summarised as:

(a) NS Power retains its obligation to serve all customers as a default supplier[4], and

(b) the institution of a Renewable to Retail ("RtR") market must not adversely affect any other wholesale or retail customers or any suppliers to NS Power[5].

The Terms of Reference[6] set out as criteria:

- scalability (and associated capability of response to uptake); and
- the solution will leverage to the extent possible the existing NSPSO market mechanisms and systems.

These criteria are best achieved by a design for simple and readily comprehensible solutions with, to the extent possible: simple implementation, predictable outcomes, and minimum regulatory or administrative burden.

<u>These design objectives are proposed as useful to the evaluation of options. We are interested to receive stakeholder comment on their utility, and on any proposed additions.</u>

The identified design options will be described in sections 2.2 to 2.5 below. Section 3 will set out the comparison of these options with due regard to these requirements and criteria, and will draw certain conclusions from these comparisons.

[4] Electricity Act 2004, as amended by the Electricity Reform Act 2013, section 3C (2)

[5] Electricity Act 2004, as amended by the Electricity Reform Act 2013, section 3G (2)

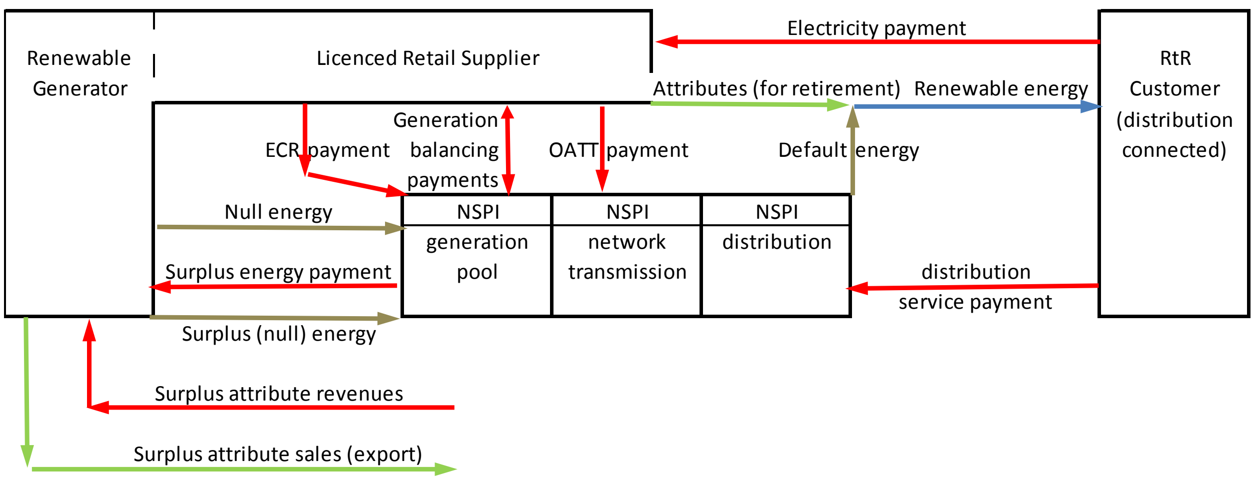
[6] The Project Terms of Reference were developed with stakeholder consultation and published on the NS Power website, http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/regulatory-initiatives/renewable-to-retail.aspx.

2.2 Disaggregated tariff option

This option was the basis of NS Power's initial thinking and of some prior discussion. It addresses each stage of the balancing and delivery process as a separate tariff.

The flows of energy, attributes and cash are summarised for this option in figure 1.

Figure 1
Disaggregated option; energy and cash flows



As noted above, it is possible that the Renewable Generator and the Licenced Retail Supplier would be the same entity or merely have a contractual relationship. The arrows to and from this entity are positioned mostly for graphic convenience as opposed to prescriptive distinction.

The distribution service payment made by the RtR customer to NS Power would be in accordance with a Board approved distribution service tariff, identified in the legislation as a deliverable.

In order to implement a modified OATT, the Licenced Retail Supplier would become a transmission customer. It would not however have its own distinct physical points of delivery, as the RtR customers will typically be embedded within distribution systems. The Licenced Retail Supplier would have to be assigned a virtual delivery point. In order to determine the value of any charge determinant at that virtual delivery point, NS Power will have to make inferences from actual RtR customer metering as discussed in section 4.2 below.

The fundamental framework of generation balancing payments (NS Power tariffs for backup/top-up and for spill) is based on measurement of hourly imbalances between generation injections and load withdrawals. If this framework is maintained, the hourly load withdrawal parameter can only be derived by considerable inference from RtR customer metering.

In any year, there should always be some surplus of the renewable generator's production over that required after appropriate loss adjustments to match the RtR customer load[7]. In order to maintain other customer cost neutrality, NS Power should pay the renewable generator the cost that NS Power avoids as a result of this surplus energy injection. This would likely be a separate Board approved rate, but would result from the same rate setting process as that used in the determination of other rates. This would complete the legislative deliverable of a new or amended non-dispatchable supplier spill tariff.

The energy provided by this renewable generator does not contribute towards NS Power's compliance with Nova Scotia's Renewable Electricity Standards (RES), so it is therefore traded as null energy – i.e. energy without renewable attributes. The renewable generator would thus be free to sell renewable attributes <u>surplus</u> to those associated with the supply to its RtR customers.

The Embedded Cost Recovery ("ECR") payment would be subject to prior Board approval. Please refer to section 5.5, below.

The Licenced Retail Supplier must therefore incorporate into its renewable electricity selling prices the amounts to recover generation balancing payments as well as the OATT charges and any ECR payments, as well as other tariffs as needed, all of which would have uncertainty, administrative complexity and delay.

It may be challenging[8] to determine (either ex ante or ex post) whether the overall impact of the disaggregated RtR framework would in fact be neutral with respect to NS Power's financial position or its full service customers.

[7] Any deficiency would likely be an infringement of a condition of the licence of the Licenced Retail Supplier, so the parties should be targeting a small surplus.

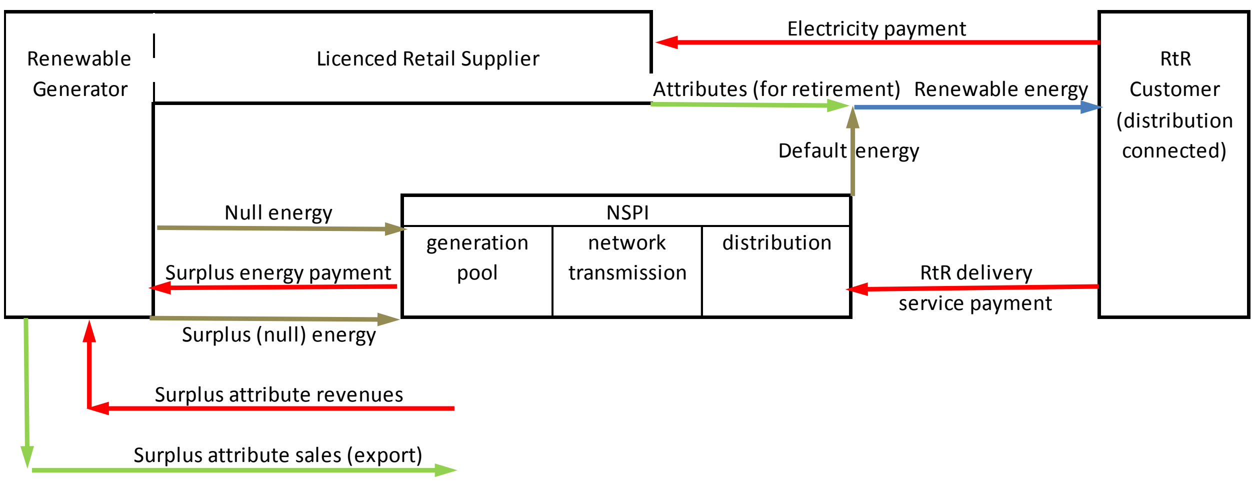
[8] The challenge is in the complexity. Each individual tariff item will presumably be designed for appropriate cost allocation, but some of the cost allocation may appropriately employ principles other than the incremental cost. The end result will be a combination of offsets which may compound small differences. Instead of a direct avoided cost determination, the net avoided generation cost for an RtR supply chain / customer would comprise an exclusion of all generation costs, a credit in some hours for spill, a charge for backup, a charge in some hours for top-up, and an ECR charge. If some of the rates are based on non-incremental cost allocation, then neutrality for other customers requires that other rates compensate.

2.3 Integrated RtR delivery service tariff

This option is a top-down approach to the design. It starts from the legislative requirement that the institution of a Renewable to Retail market may not adversely affect any other wholesale or retail customers or any other in-province suppliers to NS Power. In order that remaining customer rates not be affected, it is necessary that the reduction in total RtR customer rates (relative to NS Power full service rates) should be equal to the cost that NS Power avoids by not supplying the RtR customer with electricity. In this integrated RtR delivery service option, this is a basic design concept, rather than a test that the Board could apply to any other option.

The flows of energy, attributes and cash are summarised for this option in Figure 2.

Figure 2
Integrated RtR tariff option; energy and cash flows



The RtR delivery service payment would be in accordance with Board approved integrated RtR delivery service rates. The RtR end customer would be responsible to pay Board approved rates reflecting the NS Power full service rate minus the NS Power cost avoided by the renewable generator's provision of the equivalent quantity of null energy (over the one-year compliance period) and any associated capacity. These rates would be applied on the basis of the RtR customer metering, and would thus implicitly include the generation balancing, transmission and distribution costs. They would effectively subsume the first three deliverables contemplated in the legislation, namely a new or amended OATT, a distribution tariff, and a new or amended backup/top-up service tariff, as well as a portion of item 4, the spill tariff.

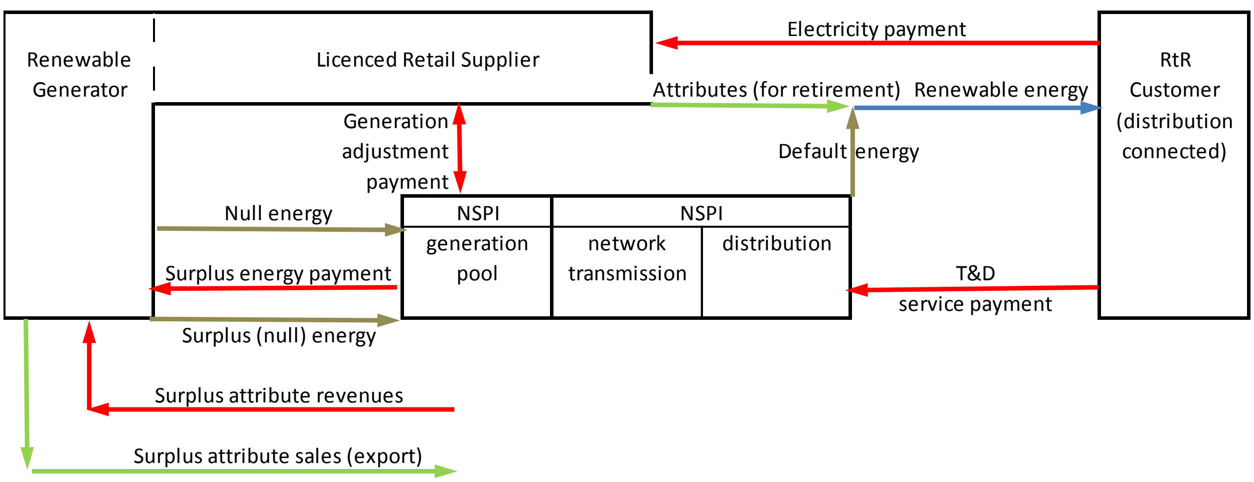
The avoided cost calculation is a fundamental aspect of this and some other options. It is discussed in more depth in section 5.

2.4 Hybrid option

The hybrid option seeks to preserve some of the transparency of separate components under the disaggregated option, while mitigating the complexity of that option. Transmission and Distribution costs are consolidated into a single T&D service payment in accordance with a Board approved joint retail T&D tariff with payments based directly on actual RtR customer metering. Generation balancing, embedded cost recovery, and avoided capacity credit are merged into a single generation adjustment payment charged on the basis of RtR customer meter data or on the basis of generation production in respect of that RtR customer load.

The flows of energy, attributes and cash are summarised for this option in figure 3.

Figure 3
Hybrid option; energy and cash flows

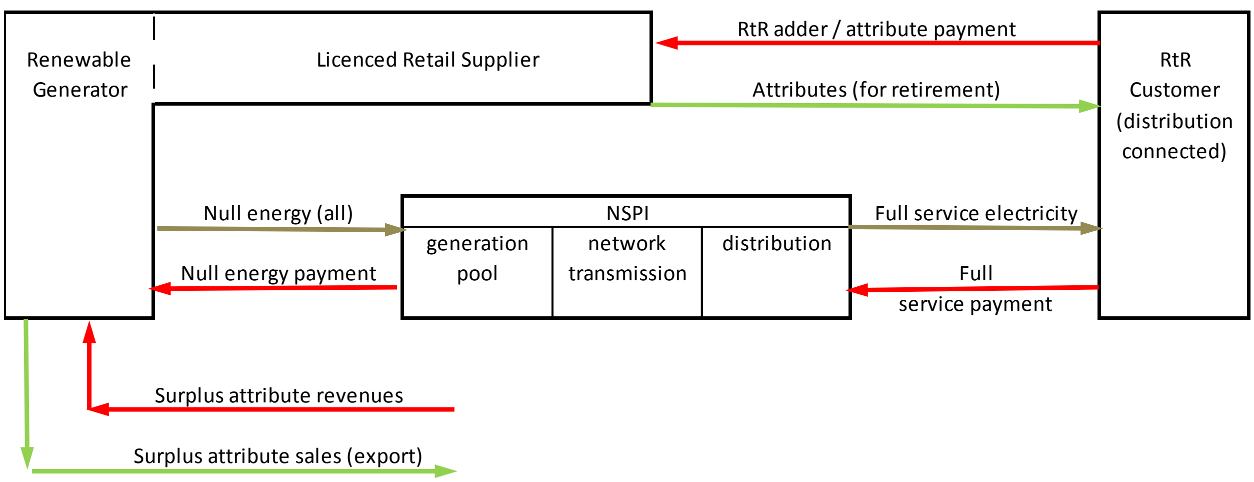


2.5 Financial market option

This could also be described as an attribute purchase option.

The flows of energy, attributes and cash are summarised for this option in figure 4.

Figure 4
Financial market option; energy and cash flows



It contemplates an “RtR adder” market framework in which:

- The NS Power market is modified to provide a right to a qualifying generator / Licenced Retail Supplier to inject electricity to the grid and receive from NS Power payment equal to the costs that NS Power thus avoids, however such avoided costs may be determined.
- NS Power full service costs and rates are unaffected.
- The customer continues to purchase all electricity from NS Power at its full service rates, and NS Power need not be aware of any contract arrangements between a Licenced Retail Supplier and a consumer except in respect of provision of meter data (if required).
- The customer pays an agreed RtR adder to the Licenced Retail Supplier.
  - This could be based on a fixed and previously agreed monthly quantity of electricity; or
  - The customer could authorise NS Power to pass on meter reading data to the Licenced Retail Supplier as a basis for charging the RtR adder on the actual consumption.

This framework has the beauty of simplicity. It shares with other proposals the challenge to establish NS Power’s avoided costs. It amounts to a null energy sale to NS Power and a retail sale (for retirement only) of renewable attributes.

This model would be the easiest, quickest and lowest cost to implement. NS Power would need to seek Board approval for a tariff, based on avoided costs, governing NS Power’s purchase of null energy sales from the renewable generation source. The only other NS Power administrative cost would arise from the provision to the Licenced Retail Supplier of metering data (if required).

<u>We seek feedback on whether the financial market option meets the needs of potential market participants and other stakeholders.</u>

<u>Are there any clarification questions with respect to any of these options?</u>

3 Comparisons and relative benefits

3.1 Licencing differences

Licencing will be the responsibility of the Board and not of NS Power, so it is outside the general scope of this white paper. The licencing requirements of the financial market option described above would differ from those of other options, but we have not noted any differences in licencing requirements that would appear to be determinative amongst the market design options under consideration. Absent identification of any such differences, the licencing requirements should therefore not have a significant impact on the relative merits of different market design options.

3.2 Option comparison tables

The comparison tables set out on the following pages seek to highlight the differences and relative merits among the options: integrated RtR delivery service; disaggregated framework; hybrid option; and the financial market option. The table is in three parts, covering: cost allocation and recovery parameters; tariff requirements; and judgmental assessments against the criteria set out in section 2.1.

Nova Scotia Renewable to Retail market design

Principal options comparison table: sheet 1, cost allocation

Description	Disaggregated tariffs	Integrated RtR delivery services	Hybrid option	Financial market option
Cost Allocation				
Distribution costs	paid by customer under a new distribution service tariff	paid by customer as part of integrated delivery tariff	paid by customer as part of delivery tariff	paid by customer as part of full service tariff
Transmission costs	paid by LRS under OATT provisions based on aggregated load / inferred hourly load profile LRS recovers under electricity price	paid by customer as part of integrated delivery tariff	paid by customer as part of delivery tariff	paid by customer as part of full service tariff
Generation balancing services	paid by LRS under backup / top-up tariff and credit under spill tariff based on aggregated load / inferred hourly load profile LRS recovers under electricity price	paid by customer as part of integrated delivery tariff	paid by LRS under generation adjustment payment LRS recovers under electricity price	paid by customer as part of full service tariff
Avoided NSPI fuel costs on RtR sales	not applicable	credited to customer in determining integrated delivery tariff	not applicable	none
Avoided NSPI capacity costs on RtR sales	not directly applicable may need recognition	credited to customer in determining integrated delivery tariff	credited to LRS under generation adjustment payment LRS may recognise in determining electricity price	credited to generator as part of renewable injection tariff
Surplus electricity (annual basis)	credited to LRS / Generator under surplus spill tariff	credited to LRS / Generator under surplus spill tariff	credited to LRS / Generator under surplus spill tariff	credited to generator as part of renewable injection tariff
Embedded Cost Recovery	requires separate determination	implicit in delivery tariff avoided cost calculation	implicit in generation adjustment payment calculation	none required

Nova Scotia Renewable to Retail market design

Principal options comparison table: sheet 2, tariff structure

Description	Disaggregated tariffs	Integrated RtR delivery services	Hybrid option	Financial market option
Tariffs requiring regulatory approval				
Full services tariffs				Unchanged from today
Distribution service	required			
OATT review	required			
T&D service			required	
Top-up and spill service	required			
Backup capacity	required			
Generation adjustment service			required	
Integrated RtR delivery services		based on full service rates minus avoided cost		
Surplus supply (based on avoided cost)	required	required	required	required, in the form of a renewable injection tariff
Embedded Cost Recovery	potentially required			

Nova Scotia Renewable to Retail market design

Principal options comparison table: sheet 3, benefits comparison against identified criteria

Description	Disaggregated tariffs	Integrated RtR delivery services	Hybrid option	Financial market option
Criteria				
Legislation compliance				
Supports obligation to serve	yes, subject to detail of ECR design etc	inherently yes	inherently yes	inherently yes
Demonstrable neutral impact on others	needs to be reflected in each element of tariff structure as opposed to globally	inherently yes	yes	inherently yes
Project terms of reference				
scalability	yes	yes	yes	yes
leveraging market mechanisms	yes, with additions required	yes, with limited adjustment	partial	yes
Provisional design objectives				
Simple & readily comprehensible solutions	comprehensible but more challenging	simplest and most transparent of the physical supply options	moderate	simplest in concept
Simple implementation	most complex	simplest of physical options	moderate	simplest
Predictable outcomes	least predictable	most predictable (RtR customer bears avoided cost uncertainty in regulatory rate setting)	somewhat predictable	most predictable (generator bears avoided cost uncertainty in regulatory rate setting)
Minimum regulatory & administrative burden	greatest complexity and burden	lowest among physical market options	moderate	lowest regulatory and administrative burden

3.3 Conclusions regarding option selection

The financial market option described in section 2.5 remains very different from the physical supply options set out in sections 2.2 to 2.4. As noted above it offers a simple and lowest cost solution.

Among the other principal options, the integrated RtR delivery service tariff option has many advantages. It builds on existing market mechanisms and tariff structures, but only to the extent that its avoided cost approach underlies several of those existing tariffs.

There will be a number of points of view in the development of tariffs or in their implementation. The different market participants have different and at times conflicting objectives. In the integrated RtR delivery service option, all of the argument is likely to be focussed into a single "avoided cost" supplement in the initial proceeding and NS Power's subsequent General Rate Applications. In the fully disaggregated option, an extensive initial regulatory process (and periodic revisions) will be held to set rates for distribution service, OATT updates, backup ,top-up and spill, as well as stranded asset discussion. Part of the work under that option will be the establishment of rates for surplus energy. The discussion will be much more granular, with focus on different aspects at different times. There is also potential for disparity of stakeholder views in the implementation by NS Power of load profiling for the inference of hourly load for transmission tariff and generation balancing settlement.

To the extent that regulatory and administrative simplicity reduces total implementation cost (as in the financial market option and the integrated RtR delivery service option), this is to the benefit of the RtR market participants or their customers.

<u>Before proceeding further, we seek stakeholder comment on</u>

- <u>the criteria used (have we missed any),</u>
- <u>the judgments made in evaluating options against the criteria, and</u>
- <u>preferences amongst the options, including reasons for such preferences.</u>

4 Metering and settlement

Load metering and settlement can have a significant impact on the design of a retail market, particularly in the circumstance where the generation (and particularly if it is variable generation) injected to the grid and the customer load will be mismatched substantially all the time**.**

4.1 Is metering necessary?

The first question is whether load metering is a necessary component of the RtR market.

It is possible to contemplate a framework in which RtR customers would effectively buy for retirement[9] a predetermined number of renewable attributes that is unrelated to their actual consumption of electricity. This is one version of the financial market framework described in section 2.5. The discussion in sections 4.2 to 4.5 of metering and settlement options is not relevant to that version of the financial market option described in section 2.5.

4.2 Metering, energy loss and load profile considerations

Some market design frameworks require explicit determination of hourly imbalances between RtR generation and RtR load. In others the imbalance has a cost, but this is embedded in the avoided cost determination and so does not require explicit hourly imbalance determination. For settlement in those frameworks, which require explicit hourly imbalance determination, hourly load data is needed. Production of such data could require the installation of hourly interval metering at delivery points of RtR customers; there would be a cost to cover metering installations and the meter reading and data processing infrastructure requirements. Available load research data by rate classes could instead be used to develop RtR customer load profiles to infer hourly data from cumulative energy meter readings. The disadvantage of reliance on inferred hourly load calculations is the delay until the next (monthly or bi-monthly) cumulative energy meter read. If a market framework requires such inferred hourly data, we would need to consider alternative approaches in respect of the inference calculation or deferral of final settlement. Similarly, transformer and line losses, as already used for the full service rate setting purposes, could be adopted for settlement of generation balancing and determination of delivery rates.

We seek comment on whether we should incorporate existing customer class metering requirements, or establish additional metering requirements for RtR customers.

[9] Retirement of the attributes implies that they are not available for further sale.

4.3 Meter ownership, meter reading and metering calculations

Metering options exist within the market models described above. NS Power could continue to own and read meters and pass necessary data on to the Licenced Retail Supplier. Or it is possible that the Licenced Retail Supplier could assume responsibility for metering. This matter will be considered further in the context of a preferred market design option.

4.4 Transfers

The transfer of a customer from NS Power full service to an RtR contract would require a meter reading. Absent special arrangements, the transfer would naturally take place at the next normal meter reading date. Consideration should be given to specially requested meter readings for transfer purposes, with an appropriate fee.

4.5 Collection and settlement cash flow

There are three technically possible configurations for collection and settlement cash flows:

- Supplier consolidated: the Licenced Retail Supplier would invoice and collect from RtR customers the NS Power delivery charges (as notified to it by NS Power) and RtR electricity charges. The Licenced Retail Supplier would pay to NS Power the delivery charges. Licenced Retail Supplier procedures in the event of customer non-payment would likely be addressed as a licencing issue.
- Split collection: NS Power would invoice and collect the NS Power delivery charge; the Licenced Retail Supplier would invoice and collect the RtR electricity charge. Each party would bear the risk for its own collections. NS Power normal non-payment procedures would apply to any shortfall in payment of delivery charges, but NS Power would bear no responsibility in respect of RtR electricity charges.
- NS Power consolidated: NS Power would collect from RtR customers both the NS Power delivery charge and the RtR electricity charge determined on the basis of the Licenced Retail Supplier's applicable tariff as advised to NS Power by the Licenced Retail Supplier. That tariff would likely be required to reflect charge determinants that were the same, for the applicable customer class, as is used by NS Power. NS Power would pass on the actual collections in respect of the RtR electricity charge, with shortfalls allocated pro rata and normal NS Power non-payment procedures.

As a matter of convenience and without prejudice to the outcome of discussion on this issue, this white paper is written from the perspective of split collection as this corresponds to the economic result of any of these settlement processes.

We seek information on stakeholder preferences among the collection and settlement arrangements as outlined above.

5 Avoided costs and ECR

Determinations of avoided costs and non-avoided costs are fundamental in some form or other to all the market design options. The results of such determinations have a significant impact on the economics of the RtR supply chain, and are therefore potentially contentious. This section of the white paper includes discussion of the principles that NS Power would expect to incorporate into its determinations for the purposes of applications to the Board.

5.1 Generation / transmission / distribution / administration

All of NS Power's prudently incurred costs are assumed to be categorized or capable of allocation among these four categories. In general:

- Generation costs include all fuel, and in respect of the generating division all fixed and variable operating and maintenance costs, depreciation, financing costs (including return on equity), purchased electricity costs net of export sales, corporate support and allocated corporate overhead.
- Transmission costs, corresponding to those allocated to transmission in determination of the OATT rates.
- Distribution costs are, in respect of the distribution division all fixed and variable operating and maintenance costs, depreciation, financing costs (including return on equity), corporate support and allocated corporate overhead.
- Administration costs are discussed as a separate category, although they may fall for rate determination into one of the three prior divisional categories. They include retail costs associated with billing, metering, call center, connection and disconnection services, etc. And they include wholesale administration costs associated with generation and transmission administration.

5.2 Monthly, seasonal or annual rates

The working assumption of the white paper is that all calculations would be based on annual totals, and therefore all rates would be constant throughout the year. Purely annual accounting in this way does however present an intra-year cash flow challenge when accounting for RtR supply and for surplus energy. This is discussed in section 7.8 below.

5.3 Avoided energy costs

The NS Power avoided energy cost is the incremental cost of the marginal MW of generation displaced by the RtR generator injection. In its simplest form, this comprises the fuel and variable operating costs of the most expensive unit operating at any time. It may in some instances be the cost of an incremental import or of a foregone export. And in practice the most expensive unit may not be capable of reduction (e.g. a coal unit already operating at its minimum), and hydroelectric generation may be used to time-shift a fossil unit reduction. In the case of variable generation, uncertainty in the production forecast may limit the fine tuning of cost avoidance.

The avoided energy cost calculation depends on the relationship of the renewable generation profile with the NS Power generation profile, and is independent of the particular load profile of any RtR customer or customer class. The avoided costs will vary depending on a number of parameters such as fuel prices. NS Power typically uses such methodology in development of annual average rates such as for Backup/Top-up and spill, and Generation Replacement and Load Following tariffs but such methodology may require modification to reflect the typical generation profile of the specific renewable technology.

5.4 Avoided capacity costs

NS Power must plan for sufficient generation on its system to meet expected demands plus a certain level of reserves. To the extent that a connected RtR generator can contribute to fulfillment of this requirement, NS Power avoids some of its need to invest for this purpose. The extent, in MW, to which a particular RtR generator contributes to the system capacity requirement is likely to be based on its technology, just as it would for NS Power or contracted generation. The value attributed to those MW of capacity contribution depends on what capacity-related costs can thus be avoided by NS Power.

The rate of investment by NS Power varies from year to year, and any investment in new assets will likely be in large discrete lumps. A small RtR generator is unlikely to avert the need for a particular new investment. It will more likely, in an era of slow demand growth, permit the deferral of such investment. A strict avoided cost calculation would therefore seek to identify the particular years in which such investment was deferred, and to allocate the RtR generation the value of that deferral (e.g. of a 50 MW gas generator deferred a year as a result of a 10 MW wind generator) in that particular year. Such an approach may however be impractical from a number of perspectives. It may therefore be more reasonable for NS Power to establish an average marginal value of capacity over its planning horizon, and to use this as a basis for determination of the avoided capital cost rate.

To the extent that the projected supply-demand balance will require no new facility investment, then the costs avoided by the RtR generator's contribution to capacity are much smaller. They represent any NS Power savings made in reduced operations, maintenance and sustenance capital.

The driver for any capacity investment is the output of NS Power's system planning process; and capacity investments are by their nature longer term investments. It will be necessary to consider in the ongoing development of the RtR market design whether the avoided capacity cost should be updated for every NS Power rate proceeding cycle, or whether an avoided capacity cost established at the time of an RtR generation investment should be held constant for a longer period.

5.5 Non-avoided costs and Embedded Cost Recovery

It is not expected that new RtR generation would result in any reduction of depreciation or financing costs, or of overhead allocated to, existing generation. Nor would deferred cost recovery mechanisms be affected. Such costs would not be avoided. To the extent that tariffs are based on avoided capacity costs, there would be no financial stranding of any existing assets or of allocated overhead.

In the case of a disaggregated tariff option, the sale of surplus energy to NS Power would be expected to reflect avoided costs. The disaggregated rate structures covering generation delivered to RtR customers should properly include a provision for recovery of costs that (a) are not avoided by virtue of the RtR supply chain, (b) are not otherwise recovered under disaggregated rates applicable to the RtR supply chain, and (c) would otherwise have been recovered through NS Power's full service rates. Such costs would typically comprise depreciation, financing and absorbed overhead of any assets declared no longer used and useful as a result of said RtR service. Such circumstances are most likely to arise when system load is reducing (over the planning horizon) faster than natural end-of-life of the generation fleet. As long as the RtR share of the system load is small, the effect is likely to be one of accelerating the end of life of near-term facilities, not of triggering new retirements. This is somewhat analogous to consideration of the capacity value under conditions of new generation investment.

There is also a range of other costs (eg deferred costs) that would need to be the subject of proper embedded cost recovery under a disaggregated tariff option.

5.6 Incremental administration costs

The implementation of the RtR market framework will tend to increase NS Power's administration costs in three areas:

- Regulatory processes to establish and from time to time update the necessary tariffs and rates

  Ongoing regulatory costs associated with the both retail and wholesale functions of the RtR market framework should properly be borne by the participants in that market. The disposition of any initial regulatory set-up costs is a matter that will require careful consideration in due course.

- Retail services incremental costs, comprising:
  - Switching to and from RtR service
  - Passing of metering information to the Licenced Retail Supplier
  - Invoicing and collection (if applicable) on behalf of the Licenced Retail Supplier (could be neutralised under a Board-approved fee to the Licenced Retail Supplier)
  - Hourly load inference calculations (for the disaggregated tariff option only)

  The retail service incremental costs should naturally be recovered through the delivery tariff charged to RtR customers. These costs should not be large, but will depend on the market design option selected.

- Wholesale services incremental costs:

  The wholesale services incremental costs of generator settlement, etc., will be small, and are naturally recovered as offsets to the avoided cost calculation and/or as elements of the generation balancing tariffs.

5.7 Avoided cost rate credit for RtR customers

Under the integrated RtR delivery tariff option, the integrated RtR delivery service rate would be calculated as follows:

- The avoided cost has an energy component and may have a capacity component. All rate classes except small customers have rates with demand and energy elements.
- The integrated RtR delivery service capacity component would be equal to the full service rate less any capacity component of avoided cost allocated to take account of loss factors, reserve margins, and peak diversity factors common to that full service customer class and where applicable to the generator location.
- The integrated RtR delivery service energy rate would be equal to the full service energy rate less the energy component of avoided cost allocated to take account of loss factors common to that full service customer class and where applicable to the generator location.
- The integrated RtR delivery service energy rate for small customers combine the two above components taking account of class customer load factors in a manner equivalent to that used for equivalent full service customer classes.

5.8 Surplus energy rates

Surplus energy rates payable to the RtR generator would comprise the avoided energy cost determined in accordance with section 5.3, plus a share of the avoided capacity cost determined in accordance with section 5.4 and allocated proportionately across all energy generated.

We seek comment on any considerations that may have been missed throughout this section 5, and on any alternative principles that should be considered.

6 Connection, network upgrade and operational integration

6.1 Generator location considerations

RtR generation may be located anywhere in the Province, but developers are expected to recognise the limitations on system capacity for new connections or include for any network upgrade costs triggered by new generation in locations without present spare capacity, and to recognise that loss factors applicable to their production may vary depending on location.

There is a potential that RtR generation and some RtR customers may be connected to the same zone of the distribution system. In that case there is a question of whether those RtR customers should have a different delivery service rate. They should not, for the following reasons:

- There is no equivalent differentiation among NS Power full service customers, notwithstanding that some may be connected to the same zone of the distribution system as NS Power generation;
- Those RtR customers are fully dependent on the transmission system for delivery of electricity according to their load profile (as opposed to the RtR generation profile); and
- Undiversified generation on a single zone of the distribution system does not have any localized capacity benefit that would reduce the need for transmission capacity.

We have not at this stage addressed the treatment of same-zone location of RtR generation and RtR load in respect of the OATT settlement under a disaggregated option.

Co-location behind a load meter would not reduce total system costs any differently than adjacent location with separate metering. Settlement on a net basis for co-location would thus represent a cost transfer to non-RtR customers. This is antithetical to the design principles for the RtR project. It is therefore proposed to prohibit net settlement of RtR generation and load.

6.2 Connection procedures

Subject to review of those procedures, it is expected that generator interconnections would be made in accordance with the standard transmission connection procedure and distribution connection procedure, as applicable, on the NS Power OASIS website.

6.3 Network upgrade costs

The Generator Interconnection Procedures for transmission and for distribution systems and the OATT will be reviewed and if necessary amended in order to ensure that RtR costs will not be borne by other system users:

- Connection costs to the point of delivery to the system will be the responsibility of the generator, as will be the costs of network improvements or upgrades solely for the benefit of that generator;
- Costs of network improvements and upgrades that also provide system benefit will be apportioned; and
- Existing repayment mechanisms that would offset generator's cost responsibilities as indicated above will not apply.

6.4 Operational integration

Requirements for outage management, forecasting, metering, etc., will be equivalent to the requirements for NS Power PPA facilities or NS Power owned facilities.

The NSPSO will have the right to call for generation curtailment (without compensation) for:

- Reliability reasons;
- Congestion relief on the transmission and if applicable distribution system; and
- System over-supply.

Details of such curtailment will be developed in later stages of the Project with due regard to existing operating procedures, permitted spill levels, and NS Power's renewable standard obligations.

<u>Stakeholders are invited to comment on any issues or considerations not covered at this time.</u>

7 Other design issues

This section of the white paper identifies a number of areas generally requiring further design development. Issues are identified by descriptive text or by bullet points, depending on the level of consideration to date.

7.1 Rate setting periods and frequency

It remains to be determined if each of the regulated rates required under the various options would be established for fixed periods (and if so what these periods would be), subject to updates linked to other NS Power rate applications, or left for application to the Board as required.

7.2 Distribution tariff development

Depending on the market design option selected for further development, there may be significant effort required for the development of a distribution service tariff.

7.3 Transmission and distribution system losses

In general, the RtR supply chain will be responsible for the transmission and distribution losses associated with its delivery to RtR customers. Transmission and distribution loss factors are standardised in NS Power's OATT and full service rate calculations and, subject to consideration of generator locational loss factors analogous to those for Point to Point service under the OATT, should be applied in the same way to RtR service.

The transmission and distribution losses can be accounted in two ways:

- As physical supply by the RtR generator, or
- As null energy makeup by NS Power

In order to preserve the integrity of the renewable energy being purchased by RtR customers, and for consistency with the present OATT provisions it is proposed to adopt the first approach. The injection required of an RtR generator to supply any RtR customer will be equal to the RtR customer load adjusted for standard distribution system losses and a standard or a locational transmission system loss factor.

7.4 Preservation of NS Power customer classes

No change to existing rate (and metering) classes

7.5 Switching to RtR service

Notice requirements (including reference to licencing provisions)

Conditions precedent

7.6 Returning to NS Power full service

Notice requirements (including reference to licencing provisions)

Conditions precedent (including any minimum service duration to avoid gaming)

7.7 Customer moves

What happens to an RtR service arrangement (e.g. terminates, moves, or transfers to new customer)?

7.8 Timing and cash flow considerations

Note that this discussion is conceptual only at this stage pending any modeling by NS Power or by individual stakeholders for their own investment considerations.

Under the integrated RtR delivery service option, there are some significant seasonal cash flow issues to be considered, particularly if the renewable technology results in seasonal production patterns. Using wind generation as the example, the wind production is likely to be higher relative to the customer load profile in winter months at the start of each calendar year. NS Power's avoided generation costs may thus be front end loaded each year relative to RtR electricity sales. The materiality will have to be determined by modeling. Consideration will also be required of how to address cash flow with respect to surplus energy sales, for which the quantity will only be determined at year end.

Under the disaggregated option the natural settlement cycle for all NS Power-Licenced Retail Supplier settlement is monthly, but with a very significant (two to three additional months) lag in NS Power's ability to determine OATT and hourly generation balancing and surplus charges/payments. The net cash flows involved may reverse from time to time due to seasonal variations and customer migration.

Stakeholders are invited to comment on the issues identified throughout this section, and on the initial thoughts set out in some sections.

Stakeholders are invited to identify any other issues for consideration in the next round of design development.

Robert Cary

Robert Cary & Associates Inc
4 College St, St Catharines, Ontario, L2R 2W7
e-mail: rcary@niagara.com
phone: 905 687 8744

PROFILE

Robert Cary & Associates Inc is a consulting business specializing in electricity markets and related commercial issues. Robert Cary has also joined Charles River Associates in late 2013 as a senior consultant, and thus undertakes certain work through CRA and certain work independently.

Expertise covers three core areas:

- Consulting in market evolution and development in Ontario and the Maritime Provinces, including market rules development and evolution, OATT development, system coordination or integration, renewable energy integration, renewable energy trading frameworks, Feed-In Tariff arrangements, clean energy standard offer programs, and greenhouse gas issues.
- High value consulting in commercial and regulatory aspects of the Ontario electricity sector. This is principally from the perspective of generators or on behalf of the Ontario Power Authority in connection with generation contracts, and includes the analysis to support project development and financing, market interaction, contract negotiation, regulatory interfaces, and expert witness assignments for litigation and arbitration.
- Chair of Horizon Utilities, which is the municipally owned electricity distributor for the Cities of Hamilton and St Catharines, serving 230,000 customers.

Rob graduated from the University of Cambridge in England, is a Professional Engineer, and an MBA. With a background in engineering and management of international projects, he has undertaken project management, business and corporate development functions, largely in the energy sector. He has been associated with the Ontario electricity sector and other electricity markets since 1990, first for AGRA Monenco, then for Westcoast Power, and since 2000 as an independent consultant.

QUALIFICATIONS

MA (physics & engineering) University of Cambridge, England, 1970
MBA, Cranfield School of Management, England, 1978
P Eng (Ontario)
Chartered Director

From: George LeBlanc <georgeleblancconsultingltd@gmail.com>
Sent: Sunday, October 19, 2014 1:52 PM
To: LEFLER, LINDA
Cc: Aaron Long; Adam Baggs; Auley Carey; Austen Hughes; Bill Mahody; Bruce Outhouse; Chris Peters; Christine Kavanagh; Dana Morin; Daniel Roscoe; David MacDougall; David McLennan; David Regan; Debbi Bolton; Don Regan; Ellen Burke; ELLIS, BILL; Eva Schmidt; FERGUSON, ERIC; GODBOUT, NICOLE; Holly Bond; James MacDuff; Jocelyn Fraser; John Athas; John Merrick; John Woods; Keith Towse; LANDRIGAN, DAVID; Leona Clements; Leonard van Zutphen; Luciano Lisi; Maggie Stewart; Mark Drazen; Melissa Whitten; MYATT, LANA; Nancy Rondeaux; Nancy Rubin; Nelson Blackburn; Paul Lewis; Paul Pynn; Peggy Merrill; Peter Craig; Richard Melanson; Rob Cary; Ron Seftel; Sandy Durling; Sandy White; Scott McCoombs; Stan Mason; rjowen@dal.ca; Steve Pronko; SUTHERLAND, LAURA; SIDEBOTTOM, MARK
Subject: Re: M06214 Renewable to Retail Presentations for Technical Conference October 9

Linda et all,

Firstly I thought the presentations and subsequent discussions on the 'details' of the 'way forward' on Oct.9 were excellent. I wasn't able to attend the June meeting, and maybe some of my points were addressed at that time, however I think we need to look at the big picture concept of RTR. I believe the overall intent of the RTR exercise is to:

- provide a competitive alternative to the present provincial power supply monopoly
- increase the provincial renewable energy power production capacity
- ultimately lower or minimize power cost increases

As a private business owner, I am only too aware of the disadvantages of doing business in NS wrt high cost of power, taxes etc. If we, as a province, are to compete globally, we must provide a competitive infrastructure which fosters, not impedes the development of new and innovative business opportunities. With that in mind....

1. I believe and got the impression at the Oct. meeting that there was a desire to 'KEEP IT SIMPLE' wrt the end use customer. There should be only one bill and it should be clear what remuneration is being paid to the RTR generator and NSPI. This would (hopefully) keep administration costs to a minimum and avoid redundant billing, metering etc. infrastructures.
2. Pg. 7 of 30, White Paper, 1st para. - ".....there should always be some surplus of the renewable generator's production over that required...." WHY. Any shortfall in the supply - load equation will be met by NS Power with subsequent profit margins. This criteria requires the RTR generator to install in the order of 150% - 200% (depending upon generation availability profile) capacity wrt the retail customer needs. Proposed compensation for this requirement is - "...NS Power should pay the renewable generator the cost that NS Power avoids as a result of this surplus energy injection." This only works if the proposed 'compensation' allows the RTR generator to be profitable wrt the required surplus generation capacity.
3. pg. 7 of 30, White Paper, 2nd para. - "The energy provided by this renewable generator does not contribute towards NS Power's compliance with Nova Scotia's Renewable Electricity Standards (RES)..." This question was asked on Oct.9 and I am not clear on the response. If RTR generation meets the 'renewable' criteria and offsets NSPower's fossil fuel requirements, why would RTR generation not 'contribute'?
4. Embedded Cost Recovery. While I understand the position put forward in the White Paper, I would challenge the overall concept wrt other 'effeciency' initiatives which are being supported by the government of NS. Do we attempt to recovery ECR from businesses and individual customers who change to LED lighting, increase insulation, switch to lower cost heating alternatives etc.? All these initiatives are an attempt to reduce the NS Power generation supply requirements. NS Power will recover in the order of 50% of these costs through 'top up power' supply anyway. I think we are missing the big picture here.
5. Pg.25, sect.6.1, last para., White Paper - "Co-location behind a load meter......It is therefore proposed to prohibit net settlement of RTR generation and load." The only 'cost transfer' to non RTR customers in this instance would be ECR. Reference my discussion in previous pt. 4.

I believe we need to foster, not discourage private power generation to the benefit of us all. Thanks for the opportunity to participate in this process,

G.

On Tue, Oct 7, 2014 at 4:23 PM, LEFLER, LINDA <Linda.Lefler@nspower.ca> wrote:

Attached are three handouts for Thursday's conference. The presentations will be in this order:

1. Renewable to Retail Market models
2. Embedded Cost recovery (ECR)
3. Distribution Tariff

Thank you.

Linda Lefler, P.Eng. | Regulatory Project Manager | **Nova Scotia Power**
1223 Lower Water Street, Halifax, NS
P.O. Box 910, Halifax, NS
B3J 2W5
T: 902-428-6196
E: linda.lefler@nspower.ca
www.nspower.ca

Canada Anti-Spam Law Notice – To stop receiving commercial electronic messages from us, please forward this email to unsubscribe@nspower.ca with the word "unsubscribe" in the subject line. | Nova Scotia Power | 1223 Lower Water Street, Halifax NS B3J 3S8 | www.nspower.ca

Confidentiality Notice - The email communication is considered confidential and is intended only for the recipient(s). If you received this email in error, please contact the sender and delete the email. Unauthorized disclosure or copying of this email is prohibited.

Attachment Limits - Emera will not accept email larger than 20MB or emails containing high risk attachments like ZIP, EXE or others that could contain viruses. If you have a business need to send such an email, please contact the recipient for instructions.

From: Luciano Lisi <luciano@cbexplorations.com>
Sent: Thursday, October 16, 2014 4:51 PM
To: LEFLER, LINDA; Aaron Long; Adam Baggs; Auley Carey; Austen Hughes; Bill Mahody; Bruce Outhouse; Chris Peters; Christine Kavanagh; Craig Whitman; Dana Morin; Daniel Roscoe; David MacDougall; David McLennan; David Regan; Debbi Bolton; Don Regan; Ellen Burke; ELLIS, BILL; Richard Melanson; Eva Schmidt; FERGUSON, ERIC; George LeBlanc; GODBOUT, NICOLE; Holly Bond; James MacDuff; John Athas; John Merrick; John Woods; Keith Towse; LANDRIGAN, DAVID; Leona Clements; Maggie Stewart; Mark Drazen; Melissa Whitten; MYATT, LANA; Nancy Rondeaux; Nancy Rubin; Nelson Blackburn; Paul Lewis; Paul Pynn; Peggy Merrill; Peter Craig; Rob Cary; Ron Seftel; Sandy Durling; Sandy White; Scott McCoombs; Stan Mason; Stephen McGrath; Steve Pronko; SUTHERLAND, LAURA; Fraser, Jocelyn
Cc: John Brereton; Robert Apold (RApold@aquacheck.ca); sthomas@scotianwindfields.ca; bthompson247@gmail.com; Leonard van Zutphen (leonard@zutphen.ca); duncan.elliot@enercon.de; peter@zutphen.ca; Friis, Doreen
Subject: Re: M06214 Renewable to Retail - follow up from October 9 conference

Please see here below the initial comments in response to Mr. Robert Carey's white paper.

CBEX INITIAL COMMENTS TO WHITE PAPER BY ROBERT CAREY & ASSOCIATES

DEAR MR. CAREY,

1) Please change the title of your white paper. I can assure you that the Renewable to Retail project was not “Nova Scotia Power”. Induced. In fact over the years NSPI has resisted the opening of the market to independents very aggressively. It was only continuous political lobbying that generated the new IPP to Retail legislation.
2) A better title may be “ IPP’s Renewable to Retail Project."
3) In your introduction you point to 3 options which “you envisage”. Please add the IPP’s long sought, and now obtainable goal, through the new legislation, of delivering renewable energy to a consumer, without being connected to NSPI’s system. It would be impossible for us as an IPP to support any presentation to the UARB that does not include this Option as well as other desirable options.

Thank you,

Luciano Lisi
President
Cape Breton Explorations Ltd.
11 Eleventh Street
Glace Bay, NS Canada B1A 4M3
Tel: 902 849 8520
Cell: 902 304 5915
Skype: lucianolisi
Web: www.capebretonexplorations.com

From: "LEFLER, LINDA" <Linda.Lefler@nspower.ca>
To: Aaron Long <aaron.long@minasenergy.com>; Adam Baggs <adam.baggs@mmspos.com>; Auley Carey <auleycarey@hotmail.com>; Austen Hughes <ahughes@naturalforces.ca>; Bill Mahody <bill@mjswm.com>; Bruce Outhouse <bouthouse@bloisnickerson.com>; Chris Peters <chris.peters@minasenergy.com>; Christine Kavanagh <ckavanagh@capebretonexplorations.com>; Craig Whitman <craig@redcamp.ca>; Dana Morin <dana@fundytidal.com>; Daniel Roscoe <droscoe@scotianwindfields.ca>; David MacDougall <david.macdougall@mcinnescooper.com>; David McLennan <dbm@highland-energy.com>; David Regan <dregan@seafortheng.ca>; Debbi Bolton <Debbi@mjswm.com>; Don Regan <dregan@town.berwick.ns.ca>; Ellen Burke <eburke@blackburnenglish.com>; "ELLIS, BILL" <Bill.Ellis@emera.com>; Richard Melanson <rmelanson@bloisnickerson.com>; Eva Schmidt <eva-lotta.schmidt@enercon.de>; "FERGUSON, ERIC" <eric.Ferguson@nspower.ca>; George LeBlanc <georgeleblancconsultingltd@gmail.com>; "GODBOUT, NICOLE" <Nicole.Godbout@nspower.ca>; Holly Bond <holly.bond@bullfrogpower.com>; James MacDuff <james.macduff@mcinnescooper.com>; John Athas <jathas@lacapra.com>; John Merrick <jmerrick@mjswm.com>; John Woods <john.woods@minasenergy.com>; Keith Towse <ktowse@lahaverenewables.com>; "LANDRIGAN, DAVID" <David.Landrigan@nspower.ca>; "LEFLER, LINDA" <Linda.Lefler@nspower.ca>; Leona Clements <lmclements@stewartmckelvey.com>; Luciano Lisi <luciano@cbexplorations.com>; Maggie Stewart <mstewart@stewartmckelvey.com>; Mark Drazen <consult@drazen.com>; Melissa Whitten <mwhitten@lacapra.com>; "MYATT, LANA" <Lana.Myatt@nspower.ca>; Nancy Rondeaux <rondeana@gov.ns.ca>; Nancy Rubin <nrubin@smss.com>; Nelson Blackburn

<nblackburn@blackburnenglish.com>; Paul Lewis <acepest@ns.sympatico.ca>; Paul Pynn <ppynn@eonwind.com>; Peggy Merrill <peggy.merrill@mcinnescooper.com>; Peter Craig <craigpt@gov.ns.ca>; Richard Melanson <rmelanson@bloisnickerson.com>; Rob Cary <rcary@niagara.com>; Ron Seftel <ron.seftel@bullfrogpower.com>; Sandy Durling <sdurling@blackburnenglish.com>; Sandy White <swhite@bloisnickerson.com>; Scott McCoombs <srmccoom@gov.ns.ca>; Stan Mason <smason@wattswind.com>; Stephen McGrath <mcgratst@gov.ns.ca>; Steve Pronko <Pronkosm@gov.ns.ca>; "SUTHERLAND, LAURA" <Laura.Sutherland@nspower.ca>; "Fraser, Jocelyn" <FraserJM@gov.ns.ca>; "Sandy White (swhite@bloisnickerson.com)" <swhite@bloisnickerson.com>; Robert Cary <rcary@niagara.com>
Cc: John Brereton <jbrereton@naturalforces.ca>; "Robert Apold (RApold@aquacheck.ca)" <RApold@aquacheck.ca>; "Craig Whitman (craig@redcamp.ca)" <craig@redcamp.ca>; "sthomas@scotianwindfields.ca" <sthomas@scotianwindfields.ca>; "bthompson247@gmail.com" <bthompson247@gmail.com>; "Leonard van Zutphen (leonard@zutphen.ca)" <leonard@zutphen.ca>; "Adam Baggs (adam.baggs@mmspos.com)" <adam.baggs@mmspos.com>; "duncan.elliot@enercon.de" <duncan.elliot@enercon.de>; "peter@zutphen.ca" <peter@zutphen.ca>; "Friis, Doreen" <FriisDA@gov.ns.ca>
Sent: Thursday, October 16, 2014 4:21 PM
Subject: M06214 Renewable to Retail - follow up from October 9 conference

The white paper and presentations from the October 9 stakeholder conference are now on NS Power's website. Your comments on the subjects discussed at the meeting are requested by Thursday, October 23. The preferred way of submitting feedback is to direct it to this email list of participants. Comments and any other project documents will also be posted to the website as they are received.

If you plan to participate further and you are not on the UARB's Participants list for this process, please contact Doreen Friis at the UARB. If you wish to be removed from this email list, please let me know. Thank you.
Sincerely,
Linda Lefler

Linda Lefler, P.Eng. | Regulatory Project Manager | **Nova Scotia Power**
1223 Lower Water Street, Halifax, NS
P.O. Box 910, Halifax, NS
B3J 2W5
T: 902-428-6196
E: linda.lefler@nspower.ca
www.nspower.ca

Canada Anti-Spam Law Notice – To stop receiving commercial electronic messages from us, please forward this email to unsubscribe@nspower.ca with the word "unsubscribe" in the subject line. | Nova Scotia Power | 1223 Lower Water Street, Halifax NS B3J 3S8 | www.nspower.ca

Confidentiality Notice - The email communication is considered confidential and is intended only for the recipient(s). If you received this email in error, please contact the sender and delete the email. Unauthorized disclosure or copying of this email is prohibited.

Attachment Limits - Emera will not accept email larger than 20MB or emails containing high risk attachments like ZIP, EXE or others that could contain viruses. If you have a business need to send such an email, please contact the recipient for instructions.

From: Luciano Lisi <luciano@cbexplorations.com>
Sent: Thursday, October 23, 2014 5:53 PM
To: Aaron Long; LEFLER, LINDA
Cc: Adam Baggs; MacDuff, James; Auley Carey; Austen Hughes; Bill Mahody; Bruce Outhouse; Chris Peters; Christine Kavanagh; Craig Whitman; Dana Morin; Daniel Roscoe; MacDougall, David; David McLennan; David Regan; Debbi Bolton; Don Regan; Ellen Burke; ELLIS, BILL; Richard Melanson; Eva Schmidt; FERGUSON, ERIC; George LeBlanc; GODBOUT, NICOLE; Holly Bond; John Athas; John Merrick; John Woods; Keith Towse; LANDRIGAN, DAVID; Leona Clements; Maggie Stewart; Mark Drazen; Melissa Whitten; MYATT, LANA; Nancy Rondeaux; Nancy Rubin; Nelson Blackburn; Paul Lewis; Paul Pynn; Merrill, Peggy; Peter Craig; Ron Seftel; Sandy Durling; Scott McCoombs; Stan Mason; Stephen McGrath; Steve Pronko; SUTHERLAND, LAURA; Fraser, Jocelyn; Sandy White (swhite@bloisnickerson.com); Robert Cary; John Brereton; Robert Apold (RApold@aquacheck.ca); sthomas@scotianwindfields.ca; bthompson247@gmail.com; Leonard van Zutphen (leonard@zutphen.ca); duncan.elliot@enercon.de; peter@zutphen.ca; Friis, Doreen
Subject: Re: M06214 Renewable to Retail - follow up from October 9 conference

Please find below comments regarding the white paper presented by Robert Carey & Associates:

1: The new act requires Nova Scotia Power to provide, in consultation with stakeholders:

3G (1) Notwithstanding Section 77 of the Public Utilities Act, on or before the applicable date prescribed by the regulations, Nova Scotia Power Incorporated shall develop in consultation with stakeholders, and file with the Board for approval, any tariffs, procedures and standards of conduct and any amendments to existing tar3
iffs, procedures and standards of conduct that are necessary to facilitate the purchase of renewable low-impact electricity as provided for in Section 3C, including
(a) a new or amended open access transmission tariff;
(b) a distribution tariff;
(c) a new or amended backup/top-up service tariff;
(d) a new or amended non-dispatchable supplier spill tariff;
(e) new or amended interconnection procedures;
(f) new or amended market rules; and
(g) any other tariffs, procedures or standards of conduct prescribed by the regulations or that the Board requires Nova Scotia Power Incorporated to develop or amend in order to facilitate the purchase of renewable low-impact electricity as provided for in Section 3C.
(2) In reviewing and approving the tariffs, procedures and standards of conduct required to be developed or amended pursuant to this Section, the Board shall be guided by the following principles:
(a) customers of Nova Scotia Power Incorporated and persons who, at the coming into force of this Section, are independent power producers or hold feed-in tariff approvals within the meaning of the regulations are not to be negatively affected if some retail customers choose to purchase renewable low-impact electricity from a retail supplier;
(b) retail suppliers and their customers are to be responsible for all costs related to the provision of service by retail suppliers to their customers that would otherwise be ththe responsibility of Nova Scotia Power Incorporated and its customers.

The above section of the act is, in our mind, the essence of the legislation as far as Nova Scotia Power is concerned.

From an IPP point of view, diving into the details of those tariffs is at the heart of the feasibility of a Renewable to Retail market.

And just as important is the ability to choose which of Nova Scotia Power services to use or not to use:

1) None of them and IPP is to provide all necessary items to both satisfy customers meeds and safety and reliability standards.
2) All of them, if the services are provided at reasonable cost that facilitates the development of the RTR market as required by the Act.
3) Some of them, as needed by the IPP or as desired by the IPP.

A stakeholder working session to dive deep into these 3 options above is absolutely necessary.

All the best,

Luciano Lisi
President
Cape Breton Explorations Ltd.
11 Eleventh Street
Glace Bay, NS Canada B1A 4M3
Tel: 902 849 8520
Cell: 902 304 5915
Skype: lucianolisi
Web: www.capebretonexplorations.com

From: Aaron Long <aaron.long@minasenergy.com>
To: "LEFLER, LINDA" <Linda.Lefler@nspower.ca>
Cc: Adam Baggs <adam.baggs@mmspos.com>; "MacDuff, James" <james.macduff@mcinnescooper.com>; Auley Carey <auleycarey@hotmail.com>; Austen Hughes <ahughes@naturalforces.ca>; Bill Mahody <bill@mjswm.com>; Bruce Outhouse <bouthouse@bloisnickerson.com>; Chris Peters <chris.peters@minasenergy.com>; Christine Kavanagh <ckavanagh@capebretonexplorations.com>; Craig Whitman <craig@redcamp.ca>; Dana Morin <dana@fundytidal.com>; Daniel Roscoe <droscoe@scotianwindfields.ca>; "MacDougall, David" <david.macdougall@mcinnescooper.com>; David McLennan <dbm@highland-energy.com>; David Regan <dregan@seafortheng.ca>; Debbi Bolton <Debbi@mjswm.com>; Don Regan <dregan@town.berwick.ns.ca>; Ellen Burke <eburke@blackburnenglish.com>; "ELLIS, BILL" <Bill.Ellis@emera.com>; Richard Melanson <rmelanson@bloisnickerson.com>; Eva Schmidt <eva-lotta.schmidt@enercon.de>; "FERGUSON, ERIC" <eric.Ferguson@nspower.ca>; George LeBlanc <georgeleblancconsultingltd@gmail.com>; "GODBOUT, NICOLE" <Nicole.Godbout@nspower.ca>; Holly Bond <holly.bond@bullfrogpower.com>; John Athas <jathas@lacapra.com>; John Merrick <jmerrick@mjswm.com>; John Woods <john.woods@minasenergy.com>; Keith Towse <ktowse@lahaverenewables.com>; "LANDRIGAN, DAVID" <David.Landrigan@nspower.ca>; Leona Clements <lmclements@stewartmckelvey.com>; Luciano Lisi <luciano@cbexplorations.com>; Maggie Stewart <mstewart@stewartmckelvey.com>; Mark Drazen <consult@drazen.com>; Melissa Whitten <mwhitten@lacapra.com>; "MYATT, LANA" <Lana.Myatt@nspower.ca>; Nancy Rondeaux <rondeana@gov.ns.ca>; Nancy Rubin <nrubin@smss.com>; Nelson Blackburn <nblackburn@blackburnenglish.com>; Paul Lewis <acepest@ns.sympatico.ca>; Paul Pynn <ppynn@eonwind.com>; "Merrill, Peggy" <peggy.merrill@mcinnescooper.com>; Peter Craig <craigpt@gov.ns.ca>; Ron Seftel <ron.seftel@bullfrogpower.com>; Sandy Durling <sdurling@blackburnenglish.com>; Scott McCoombs <srmccoom@gov.ns.ca>; Stan Mason <smason@wattswind.com>; Stephen McGrath <mcgratst@gov.ns.ca>; Steve Pronko <Pronkosm@gov.ns.ca>; "SUTHERLAND, LAURA" <Laura.Sutherland@nspower.ca>; "Fraser, Jocelyn" <FraserJM@gov.ns.ca>; "Sandy White (swhite@bloisnickerson.com)" <swhite@bloisnickerson.com>; Robert Cary <rcary@niagara.com>; John Brereton <jbrereton@naturalforces.ca>; "Robert Apold (RApold@aquacheck.ca)" <RApold@aquacheck.ca>; "sthomas@scotianwindfields.ca" <sthomas@scotianwindfields.ca>; "bthompson247@gmail.com" <bthompson247@gmail.com>; "Leonard van Zutphen (leonard@zutphen.ca)" <leonard@zutphen.ca>; "duncan.elliot@enercon.de" <duncan.elliot@enercon.de>; "peter@zutphen.ca" <peter@zutphen.ca>; "Friis, Doreen" <FriisDA@gov.ns.ca>
Sent: Thursday, October 23, 2014 4:52 PM
Subject: Re: M06214 Renewable to Retail - follow up from October 9 conference

Hi Linda,
Attached please find our comments.
Kind regards,

Aaron Long, P.Eng., M.Sc.
Director of Business Development
Minas Energy
902-497-1447 (c)
www.minasenergy.com

On Thu, Oct 23, 2014 at 4:26 PM, MacDuff, James <james.macduff@mcinnescooper.com> wrote:
Nicole,

Please see attached comments from Port Hawkesbury Paper on the Renewable to Retail process.

James

From: LEFLER, LINDA [mailto:Linda.Lefler@nspower.ca]
Sent: October 16, 2014 4:21 PM
To: Aaron Long; Adam Baggs; Auley Carey; Austen Hughes; Bill Mahody; Bruce Outhouse; Chris Peters; Christine Kavanagh; Craig Whitman; Dana Morin; Daniel Roscoe; MacDougall, David; David McLennan; David Regan; Debbi Bolton; Don Regan; Ellen Burke; ELLIS, BILL; Richard Melanson; Eva Schmidt; FERGUSON, ERIC; George LeBlanc; GODBOUT, NICOLE; Holly Bond; MacDuff, James; John Athas; John Merrick; John Woods; Keith Towse; LANDRIGAN, DAVID; LEFLER, LINDA; Leona Clements; Luciano Lisi; Maggie Stewart; Mark Drazen; Melissa Whitten; MYATT, LANA; Nancy Rondeaux; Nancy Rubin; Nelson Blackburn; Paul Lewis; Paul Pynn; Merrill, Peggy; Peter Craig; Richard Melanson; Rob Cary; Ron Seftel; Sandy Durling; Sandy White; Scott McCoombs; Stan Mason; Stephen McGrath; Steve Pronko; SUTHERLAND, LAURA; Fraser, Jocelyn; Sandy White (swhite@bloisnickerson.com); Robert Cary
Cc: John Brereton; Robert Apold (RApold@aquacheck.ca); Craig Whitman (craig@redcamp.ca); sthomas@scotianwindfields.ca; bthompson247@gmail.com; Leonard van Zutphen (leonard@zutphen.ca); Adam Baggs (adam.baggs@mmspos.com); duncan.elliot@enercon.de; peter@zutphen.ca; Friis, Doreen
Subject: M06214 Renewable to Retail - follow up from October 9 conference

The white paper and presentations from the October 9 stakeholder conference are now on NS Power's website. Your comments on the subjects discussed at the meeting are requested by Thursday, October 23. The preferred way of submitting feedback is to direct it to this email list of participants. Comments and any other project documents will also be posted to the website as they are received.

If you plan to participate further and you are not on the UARB's Participants list for this process, please contact Doreen Friis at the UARB. If you wish to be removed from this email list, please let me know. Thank you.
Sincerely,
Linda Lefler

Linda Lefler, P.Eng. | Regulatory Project Manager | **Nova Scotia Power**
1223 Lower Water Street, Halifax, NS
P.O. Box 910, Halifax, NS
B3J 2W5
T: 902-428-6196
E: linda.lefler@nspower.ca
www.nspower.ca

Canada Anti-Spam Law Notice – To stop receiving commercial electronic messages from us, please forward this email to unsubscribe@nspower.ca with the word "unsubscribe" in the subject line. | Nova Scotia Power | 1223 Lower Water Street, Halifax NS B3J 3S8 | www.nspower.ca

Confidentiality Notice - The email communication is considered confidential and is intended only for the recipient(s). If you received this email in error, please contact the sender and delete the email. Unauthorized disclosure or copying of this email is prohibited.

Attachment Limits - Emera will not accept email larger than 20MB or emails containing high risk attachments like ZIP, EXE or others that could contain viruses. If you have a business need to send such an email, please contact the recipient for instructions.

Notice This communication, including any attachments, is confidential and may be protected by solicitor/client privilege. It is intended only for the person or persons to whom it is addressed. If you have received this e-mail in error, please notify the sender by e-mail or telephone at McInnes Cooper's expense. Avis Les informations contenues dans ce courriel, y compris toute(s) pièce(s) jointe(s), sont confidentielles et peuvent faire l'objet d'un privilège avocat-client. Les informations sont dirigées au(x) destinataire(s) seulement. Si vous avez reçu ce courriel par erreur, veuillez en aviser l'expéditeur par courriel ou par téléphone, aux frais de McInnes Cooper.

MinasEnergy
POSITIVE SOLUTIONS

October 23, 2014

Linda Lefler, P.Eng.
Regulatory Project Manager
Nova Scotia Power
1223 Lower Water Street
Halifax NS B3J 2W5

Delivered via email to linda.lefler@nspower.ca

Re: Stakeholder response to material presented during the October 9th stakeholder conference

Dear Linda,

Thank you for providing Minas Energy with the opportunity to comment on the Rob Cary whitepaper and other material presented at the October 9th stakeholder conference. We offer the following points in bullet form at the expense of elegant prose, with the theme being that this process needs to appreciate the challenges associated with developing projects that could offer competitive supply. To be clear, there is no point developing a market model that will not enable project financing for competitive supply.

We would also like to stress that it is interesting that entities contemplating competitive supply are offering comments regarding what is important to proponents which may be desirable or undesirable to NSPI. Under this scenario, proponents are educating the incumbent utility which is well positioned to design a market that will result in a limited take up of competitive supply.

- While in theory everyone would support the concept of selecting a market structure that has the minimum practical regulatory or administrative burden, such a choice enables NSPI to maintain the most control of the market. There are detrimental implications to project financing in this type of scenario; therefore, we cannot support the Financial Option.

- A compromise between complexity and utility control lies either in the Integrated or Hybrid Options.

- The compliance obligations listed on Rob Cary's slide 5 (Working Assumptions -2) should remain under the licensing process, which is separate from a market design process or tariff qualification process. More specifically, an LRS should obtain and maintain a license, which is the only qualification to participate in the market (subject to adhering to the GIP).

- The regulations state that no existing generator shall be harmed through the creation of this market; however, some existing facilities chose to interconnect using Energy Resource Interconnection Service to reduce construction cost by bearing the risk of curtailment. Why should this market be designed to provide curtailment certainty to an existing project that was unwilling to pay for the benefits of Network Resource

MinasEnergy
POSITIVE SOLUTIONS

Interconnection Service? The option to pay for and upgrade to Network Resource Interconnection Service could be made available to existing facilities connected with Energy Resource Interconnection Service.

We are deferring our comments on the issues of avoided and stranded costs as per the NSPI suggestion at the October 9th conference and look forward to an engaging discussion in the near future. We would also like to stress that if we are not careful, the current process will ultimately lead to an argument before the regulator on the issue of avoided and stranded costs. Minas Energy suggests that significant conference time be afforded this important discussion, avoiding the situation where a single, short session is convened to deal with the issue as a checked box exercise. As per the suggestion put forward by John Woods, let us collectively endeavor in good faith to work out as much as we can in advance of going before the regulator.

We are available to discuss any of these comments at a time of your convenience, or that of anyone copied on the email chain.

Yours sincerely,

Aaron Long
Director of Business Development

Natural Forces Wind Inc. 1801 Hollis Street, Suite 1205, Halifax, Nova Scotia, Canada, B3J 3N4. Tel: +1 (902) 422 9663. Fax: +1 (902) 422 9780. www.naturalforces.ca

Linda Lefler, P.Eng.
Regulatory Project Manager
Nova Scotia Power
P.O. Box 910
Halifax, NS
B3J 2W5

23rd October 2014

RE: Comments on Renewables to Retail Project – White Paper on Market Design (Case M06214)

Dear Ms. Lefler,

Natural Forces Wind Inc. is an independent power producer based in Halifax Nova Scotia with 5 projects operating in the Maritimes (3 in Nova Scotia) and a further 2 under construction (both in Nova Scotia). Our company develops finances, constructs and operates all of our own projects and is one of the few Nova Scotia based companies who can execute renewable energy projects in-house. Our leadership team has experience of more than 50 completed renewable energy projects across 9 countries and we are excited to be able to contribute our expertise and experience to the success of the Renewables to Retail Project.

We commend the author of the White Paper on a clear and succinct summary of some of the options to be considered in the design of a market and will respond to some of the specific questions contained within the paper. There are some more fundamental questions that we wish to raise regarding the project that we set out below:

1. What is the objective of the Renewables to Retail Project?

We are clear that at a high level the objective is to facilitate renewable energy projects in supplying renewable energy to retail customers. What we are not clear on is by what yardstick the project's success of failure shall be measured. In other markets where this concept has been implemented implementation teams have been given specific targets to achieve (i.e. x% of the market was to be contracted with new market entrants by y date). These targets gave prospective market entrants the confidence that the policy objective was clear and that a market would exist prior to entry. The other potential benefit of establishing a target market size is that an idea of the costs that must be made up to the customers who remain with NSPI are better understood.

2. The nature of competition

It seems to us a fundamental contradiction in the project that on the one hand the policy objective is to introduce competition in the electricity market and on the other hand the incumbent is guaranteed that there will be no negative financial consequences of such a market opening. One definition of competition is "the effort of two or more parties acting independently to secure the business of a third party by offering the most favorable terms." The two parties here are the incumbent, NSPI, and the new entrant and the third party is the retail customer. We do not understand how the new entrant can ever seek to secure new customers from the incumbent on more favorable terms when they at the same time must keep the incumbent whole financially.

3. Consultation process

We have a number of concerns regarding the consultation process:

- We are confused as to how it can be that the Party who is supposed to be giving up market share, NSPI, can be tasked with taking the reins on implementing the project.
- Secondly the structure of the process is being run along the same lines as the IRP with technical conferences and a request for comments on papers. We would have thought that if the policy objective was to get projects built a series of bilateral meetings could be held during which prospective market entrants could share commercially sensitive business ideas such that the implementation team could better understand some of the business structures that could work and progress the implementation accordingly. Once the implementation team knew the business models that were of interest to the different IPPs, the consultant would be able to use that as an input into the market design process.

4. The results of the Integrated Resource Plan

The three candidate resources plans put forward by NSPI in the final IRP report to the UARB this month contain very similar projections as regards new generation over the next 5 years. All three show minimal incremental capital investment required to meet emissions and renewable energy requirements out to 2020. In that context we are further confused as to the policy objective of the Project: on the one hand there is an objective to get in-Province renewable generators to supply retail customers but on the other hand the IRP is stating that no new capacity is required to meet demand and environmental conditions.

5. Review of the White Paper

Turning to the White Paper we make the following comments as requested:

Section 2.1: Criteria for option design and selection

Please see our comments above as regards policy objectives and competition.

Sections 2.2 – 2.5 & 3: Market Design Options & Comparisons of the Relative Benefits

We found the description of the four options to be very useful for us to understand the market concepts being considered. We are struggling to provide meaningful feedback in the absence of worked examples indicating the level of charges one would expect for the various elements based on other jurisdictions. Nonetheless we make a number of observations as follows:

- The level of effort in implementing the market design should be considered in the context of the expected size of the prospective market. If it is expected that the market will consist of a single generator with a distribution level project then we can understand why the lowest level of effort (i.e. the financial option) would be attractive to policymakers. If however, the objective is to have a structure that is scalable and works for numerous generators then the disaggregated tariff option would make most sense. We return back to our question regarding the policy objective of the project.

- The disaggregated tariff option appears to be the only market design that will fulfill the objective of an open and transparent market to foster competition. If this option were to be implemented it would be critical that the OATT payment and distribution service payments be independently approved annually by the UARB and that they be benchmarked against other comparable jurisdictions. The metrics applied to the Embedded Cost Recovery tariff would need to be looked at carefully. Another thing to consider is the cost of a top-up service should the renewable generator fail to supply the required energy in a given year.
- We do not believe that the Options 2 and 4 will work as the generator revenue stream is based mainly on avoided cost. That is not to say that avoided cost is not included in all of the options, just the manner in which it is applied is different.
- With Option 4 the supplier will by default be always more expensive than NSPI (assuming that the RtR adder is above zero) thus inhibiting competition.
- There are merits to Option 3 but the increased transparency of separate charging and annual review by the UARB as per Option 1 would provide increased confidence for new entrants.

<u>Sections 4: Metering and settlement</u>

Metering, energy loss and load profile consideration: We believe that settlement should be calculated on an annual basis with surplus energy and top-up energy being provided at avoided cost.

Collection and settlement cash flow: We return to the policy objective question. If the policy objective is to foster real choice for the electricity consumer then the billing should be made by the Licensed Retail Supplier. In order to believe that choice exists they must be able to see physical evidence that that choice exists and the most regular contact between a electricity supplier and a customer is through the billing experience.

<u>Section 5: Avoided Costs and ECR</u>

The question of avoided cost calculation is related to the market design. We have stated above that we are opposed to a market design that sets the majority of generator's revenue on avoided cost. Thus on the basis that the avoided cost is only used for the calculation of surplus energy payments we believe that the avoided energy cost is the most appropriate metric. Secondly, one would question the merits of an avoided capacity calculation when it is clear that there is limited requirement for new capacity on the system for some years to come.

<u>Section 6: Connection, network Upgrade, and operational integration</u>

We have no particular comments on this at this time.

<u>Section 7: Other design issues</u>

Although not mentioned in the White Paper, there was some discussion during the most recent technical conference that customers seeking to leave NSPI and enter into a supply agreement with a new market entrant would be required to pay some form of an exit fee to NSPI. Exit fees would be a huge impediment to participation of retail customers in a new market and The concept of an exit fee brings up several questions:

1. How will new customers or a new market entrant that did not have a previous contract with NSPI, be treated in Renewables to Retail? What is the definition of such a new customer – would it be an entirely new connection nor would a connection that changed ownership be a 'new customer.'
2. Do customers who leave NSPI and then rejoin get their exit fee back once they rejoin NSPI?
3. How are partial loads treated in respect to exit fees?
4. If NSPI still plans for customers who have entered the Renewables to Retail program, how will this not increase the costs to existing customers?

There is currently no fee to current customers to leave the NSPI system (for example if a factory closed or a property was abandoned), and how new customers would be treated would be difficult to govern. For this reason we would see that there should be no exit fees as customers leaving NSPI happen currently regardless of the renewable to retail program.

We thank NSPI for the opportunity to comment on the market design white paper and look forward to further engaging as the project develops. We remain available at all times for further consultation.

Yours sincerely,

John A. Brereton

President

McINNES COOPER
LAWYERS | AVOCATS

James A. MacDuff
Direct +1 (902) 444 8619
james.macduff@mcinnescooper.com

Purdy's Wharf Tower II
1300-1969 Upper Water Street
PO Box 730
Halifax NS
Canada B3J 2V1
Tel +1 (902) 425 6500 | Fax +1 (902) 425 6350

Our File: 100384
October 23, 2014

Ms. Nicole Godbout
Regulatory Counsel
Nova Scotia Power
P.O. Box 910
Halifax, NS B3J 2W5

Dear Ms. Godbout:

Re: Renewable to Retail Process – Feedback on October 9, 2014 Technical Conference

On October 3, 2014, Nova Scotia Power Inc. ("NS Power") circulated a White Paper on Renewable to Retail market design, written by NS Power's consultant Robert Cary. On October 7, 2014, NS Power circulated three presentations which were reviewed with stakeholders at the technical conference on October 9, 2014. Please accept the following feedback on behalf of Port Hawkesbury Paper LP ("PHP").

PHP's understanding is that the purpose of the Renewable to Retail process is to develop and implement a framework in Nova Scotia that will provide renewable electricity suppliers with the opportunity to sell renewable electricity directly to retail customers and to provide choice to Nova Scotia customers who may wish to acquire electricity directly from a renewable electricity provider. In order for this process to be successful, it is critical that the tariffs, procedures, standards of conduct, and other mechanisms that need to be developed as part of the process result in the creation of a truly functioning market in which new renewable projects can be financed and constructed. The process will have failed to achieve its intended goal if the market structures that are ultimately implemented do not provide the necessary flexibility and levels of certainty that are required for renewable electricity suppliers to pursue the potential development of new projects and to market their product to purchasers of electricity.

As noted at the technical conference, it is also important that the market structures that are established provide retail customers with the opportunity to receive competitive service from renewable electricity suppliers for only a portion of their load requirements.

PHP appreciates the opportunity to provide this feedback and looks forward to the ongoing collaborative development of a successful renewable to retail market in Nova Scotia.

Yours truly,

James MacDuff

cc: Interested Parties

(18400889)

Oct 23, 2014

Linda Lefler, P.Eng.
Regulatory Project Manager
Nova Scotia Power Inc.
1223 Lower Water St.
Halifax, Nova Scotia
B3J 2W5

RE: M0614 –Submission Regarding Oct 9th, 2014 Technical Conference

Scotian WindFields Inc. welcomes the opportunity to participate in the Renewable to Retail Market Opening process and submits the below comments and suggestions regarding the October 9th, 2014 Technical Conference and supporting White Paper and documentation.

The comments attached in this correspondence outline recommendations and considerations concerning the below points:

- Supplier Consolidated Billing Model
- Infrastructure Ownership
- Suggested RtR Framework Option
- Avoided, Non-Avoided and Embedded Costs

Should you require any clarification or further details on and of the points included in this response, please do not hesitate to contact Scotian WindFields Inc. directly.

Thank you for your consideration of these comments and we look forward to further discussion and analysis.

Sincerely,

Daniel Roscoe, P.Eng.
Chief Operating Officer
Scotian WindFields Inc.

Scotian WindFields
Community Owned. Naturally.

1) Supplier Consolidated Billing/Pricing model.

Scotian WindFields Inc. would like to voice support for a Supplier Consolidated model for Collection and Settlement Cash flow, as described in section 4.5 of the October White Paper.

Scotian WindFields Inc. feels strongly that in order to maintain simplicity and comprehensibility of the Renewable to Retail system - as outlined in the Criteria of the White Paper – a single electricity bill, from the Licensed Retail Supplier, is necessary. The coordination and payment of multiple charges and bills from multiple entities will work to make the program prohibitively complicated for many potential RtR customers.

Furthermore, this allows for the various charges, tariffs and payments to be handled between the Licensed Retail Supplier and Nova Scotia Power Inc. These charges can be disclosed to the RtR customer, as a billing item or otherwise, but will not be the responsibility of the customer to coordinate, negotiate or pay directly.

2) Distribution, Metering and Service Infrastructure Ownership

Scotian WindFields Inc. would like to request that an option exist that allows the Licensed Retail Supplier to own independent metering, communication and other service infrastructure equipment. This will allow for bundling of packages and services for customers that are offered by the Licensed Retail Supplier, while NSPI will still maintain ownership and control of interconnection, transmission and distribution infrastructure.

Under this framework, it is proposed that in the event of service interruption, service outages or interconnection problems, the customer will still be advised to contact Nova Scotia Power Inc. directly, as the owners and operators of the transmission and distribution infrastructure.

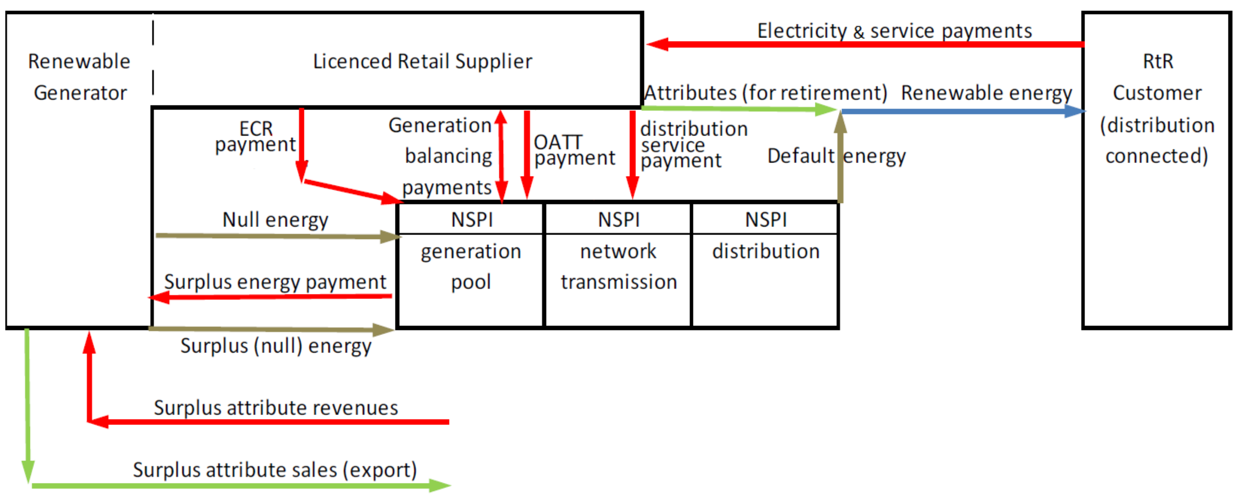
108F Trider Cres, Dartmouth, NS B3B-1R6|
info@scotianwindfields.ca | www.scotianwindfields.ca

Scotian WindFields
Community Owned. Naturally.

3) Suggested RtR Framework Option

To supplement the information given in the remaining portions of this submission, Scotian WindFields Inc. would like to suggest the below framework as an Option for consideration of the Renewable to Retail market framework.

This model is based on the Option outlined in section 2.2 of the White Paper – Disaggregated Tariff Option. Scotian WindFields Inc. agrees with this approach, and would like to suggest further simplifying the experience for the RtR customer by being responsible for a single payment, made to the Licensed Retail Supplier. All payments are tariffs, as well as the details of compliance, energy metering and interconnection will all be considered and negotiated between Nova Scotia Power Inc., the Licensed Retail Supplier and the Renewable Generator.



Scotian WindFields
Community Owned. Naturally.

4) Avoided, Non-Avoided and Embedded Costs

Scotian WindFields Inc. recognizes the need for further analysis, discussion and resulting tariff regarding Avoided, Non-Avoided and Embedded Costs and offers the below comments.

a) Avoided Energy
Scotian WindFields Inc. suggests that an hourly in advance model should be developed for calculation of avoided costs as well as top up and spill rates. This should be done using averages from previous years to avoid the need to be calculated dynamically after the fact. This respects the fact that energy is more expensive in the winter heating months, therefore it should be more expensive for Licensed Retail Suppliers to top up during that time, as well as spilled energy to reflect a higher marginal cost.

b) Avoided Capacity
Most types of renewable energies are better suited to certain types of year. Therefore, Scotian WindFields Inc. feels that seasonal capacity requirements be developed by Nova Scotia Power Inc., and seasonal contributions for each type of renewable generation be agreed to for their contribution to this requirement.

c) Non-Avoided and Embedded Costs
From the discussion on Oct. 9th it is clear that non-avoided and embedded costs will be a challenging topic on which to come to agreement. Scotian WindFields Inc. agrees with the presenters that much more detailed discussion is needed. To facilitate that discussion, we feel it would be useful for NSPI to place these costs into three different categories:

i) Those required for the provision of service to RtR Customers.

ii) Those required for the “obligation to server” RtR Customer if they return to NSPI.

iii) Those not associated with the Renewable to Retail program in any way.

NOVA SCOTIA
Department of Justice
Legal Services Division

PO Box 7
1690 Hollis Street, 6th Floor
Halifax NS B3J 2L6

Phone: (902) 424-6288
Fax: (902) 424-7120
E-mail: MCGRAST@gov.ns.ca

Stephen T. McGrath
Team Lead

October 24, 2014
Via EMAIL: Nicole.godbout@nspower.ca

Nicole Godbout, Regulatory Counsel
Nova Scotia Power Incorporated
1223 Lower Water Street, Halifax, NS
B3J 3S8

Dear Ms. Godbout:

RE: M06214 Renewable to Retail technical conference, October 9th

After reading the "Market Design" whitepaper by Rob Cary and attending the technical conference on October 9, 2014, the Department of Energy (herein referred to as "the Department") would like to offer the following comments:

1. The Electricity Act, clearly indicates that the purchase, sale and licensing relating to transactions between retail suppliers and retail customers under the act is restricted to **renewable low-impact electricity** (see s.2(c) and s.3C(1) in particular). This should be interpreted as the sale of electricity including the associated environmental attributes to a retail consumer in Nova Scotia.

2. The Department respectfully suggests that ensuring transparency and openness of tariff structure and market model be considered a guiding principle for the development of the Renewable to Retail market.

3. The Department would also respectfully suggest that the market design should have the flexibility to allow market participants to innovate and compete. Given the pace of technological evolution within the electricity generation sector it is very likely that the market will encounter future entrants with very different cost and supply structures from those seen today. The chosen market model should have enough inherent flexibility to avoid additional regulatory burden each time a new market entrant appears.

4. Subsection 3G(2) of the Electricity Act requires that all costs for the market opening be borne by retail suppliers and their customers. As such, there should be no material difference in the costs to be recovered from the Renewable to Retail market participants between the market models. The decision on market model should therefore be based on other factors such as transparency, flexibility and regulatory burden.

Addressee
Page 2
Date

Respectfully,

Stephen T. McGrath

BLACKBURN ENGLISH
BARRISTERS SOLICITORS

E.A. Nelson Blackburn, Q.C.
David F. English, B.Comm., LLB
Joseph M.J. Cooper, Q.C.
Janet Nolan Conrad, B.A., LLB
Paul B. Miller, MBA, LLB
Derek M. Land, B.A., LLB
Martha L. Beyea, LLB
Ellen R. Burke, LLB
Jonathan P. English, B.B.A., LLB
Thomas J. Kayter, J.D.

Suite 231, Bedford House
Sunnyside Mall
1595 Bedford Highway
Bedford, Nova Scotia
Canada, B4A 3Y4
Telephone: (902) 835-8544
Fax: (902) 835-4310
E-mail: bedford@blackburnenglish.com
www.blackburnenglish.com

287 Highway #2
Enfield, Nova Scotia
Canada, B2T 1C9
Telephone: (902) 883-2264
Fax: (902) 883-8744
E-mail: enfield@blackburnenglish.com
www.blackburnenglish.com

OUR FILE:

October 24, 2014

Ms. Linda Lefler
Nova Scotia Power Inc.
1223 Lower Water Street
Halifax, NS B3J 2W5

Dear Ms. Lefler:

Re: SBA Comments on NS Power's Renewables to Retail Technical Session 2, October 9, 2014

Please accept this letter as the Small Business Advocate's comments on Nova Scotia Power's Renewables to Retail Technical Session 2 October 9, 2014.

I. Introduction

The Small Business Advocate ("SBA") once again would like to emphasize that the small businesses of Nova Scotia are grateful for the opportunity to participate as an active stakeholder in this area. The SBA views that the opportunity for renewable energy developers to sell their output directly to retail customers is something beneficial to Nova Scotia. The SBA, as described in these comments, can't stress enough the importance of NS POWER constructing the Renewable to Retail ("RtR") processes, tariffs, and costs to conform to the guidelines in the enabling legislation. The SBA recognizes that it is critical that no costs are shifted to any customers, especially to and among small businesses, as part of the RtR process. The SBA offers these comments as its next step in participation in NS Power's development of options to implement the provincial legislation to enable renewable energy projects to sell their output to specific retail customers.

II. SBA Concerns

The SBA comments recognize that there are a number of reasons for the legislature to desire to create enablers for the uncommon transaction of Renewable Energy based Generators to sell directly to retail customers. Some of these reasons are:

1. Promote the development of clean energy generating capacity,

2. Reduce emissions from electric generation,
3. Allow customers to exercise choice,
4. Provide Renewable Energy Developers with additional potential buyers of their output.

The SBA supports the legislation as passed in that it provides that NS POWER develop a specific framework for the RtR transaction **and** creates the requirement that customers not involved in the RtR transaction not be impacted. These customers must not have costs shifted to them. All NS POWER costs to accommodate the RtR transaction whether it be new or additional meters or a change in generation reserve requirements in order to maintain system reliability must be paid by the renewable energy supplier or the RtR customer buyer. Subsidization is to be avoided. Subsidization is not a tool to stimulate renewable energy development.

The SBA's concern is that some parties may have very liberal interpretations of the no subsidization mandate. A key component in setting up the RtR process is the determination of **avoided costs** for energy, capacity and ancillary services. The process must estimate these costs as accurately as possible for each specific renewable energy generation facility. We cannot choose to use avoided costs created for other purposes, such as interruptible service tariffs simply because they are available. We cannot use generic estimates of production from renewable energy generation involved in the RtR transaction.

Unless a mechanism is developed for plant specific avoided costs subsidization via cost allocation shifting will occur. In addition the avoided costs must be used as close to a real time basis as possible. A use of a single annual avoided energy cost number rather than hourly values will create subsidization. In some resource planning and rate making activities the future avoided capacity costs are paid out early even though there are no costs that are related to capacity at this time. Any front-end loading of avoided capacity costs into the avoided costs used to develop RtR tariff pricing will create subsidization. The SBA wants NS POWER to develop the transaction process and tariff pricing that avoids creating subsidization as required by the legislation, no matter how complicated these processes need to be.

III. Comments on NS Power's Approach to Date

If Renewables to Retail results in increased development of renewable energy resources AND does not create any subsidizations the legislation will be a great success. If the RtR transaction process is set up correctly, i.e. without subsidization and little to no additional renewable energy is developed the legislation and its implementation is also a success. If RtR subsidization is necessary to stimulate the renewable market, the implementation has not complied with the legislation. It is for these reasons that stakeholder involvement in the design the RtR processes and tariffs is important. The SBA is appreciative of the close adherence by NS POWER to the Terms of Reference and their facilitation of stakeholder input. This comment period is a fine example. We have found the NS POWER thoughts represented in the two technical sessions were thought, well explained and fully intended to comply with the legislation. The SBA has appreciated the distribution of materials prior to the technical sessions.

The SBA is also pleased that NS POWER has developed several approaches for discussion and consideration. While retail choice for all generation is generally handled similarly within North

America, specific focus on renewable energy being sold to retail customers can be accomplished in several ways. The SBA believes that any of the approaches, discussed below, can be used to create the processes for the RtR transactions without subsidization.

IV. Comments on Specific Aspects of the Technical Session Presentations

Embedded Cost Recovery - The SBA is pleased that NS POWER has indeed placed embedded cost recovery treatment in a priority position to address. The SBA agrees that customers who partially or fully leave the generation service of NS POWER opting for renewable energy are still obligated to pay a pro rata amount of recovery of any deferred costs that were incurred while that customer was a full NS POWER customer. The SBA agrees that in order to avoid subsidization that the FERC-based lost revenue approach can be used.

Delivery Service Tariff - The SBA would like to see the elements that NS POWER described for the Distribution Service Tariff on October 9th be implemented. In establishing the RtR transaction this tariff will be the main enabler. It is important that all the details of the service be contained in the tariff. The SBA favors setting up the RtR where the customer remains first a customer of NS POWER and then also a customer of the renewable energy provider. In the presentation material NS POWER refers to these as Licensed Retail suppliers ("LRS"). Even if customers contract with suppliers that can send enough renewable energy into the grid in each hour to match the customers load in that hour, the service obligations of the utility, NS POWER are still the most important. NS POWER will essentially fill in any shortfalls of energy or capacity. NS POWER will be the administrator of the RtR market and provide OATT services. NS POWER will continue to maintain the distribution service, including outage restoration. NS POWER should still be the provider of metering, billing and customer service. The SBA does not see it necessary or desirable to have any of these functions leave the responsibility of the regulated utility, allowing the UARB to provide regulatory oversight on rates and service issues. The LRS may also bill and have customer service of course.

Market Design - The SBA appreciated the thoughts developed by NS POWER and its consultant Robert Cary & Associates regarding Market Design. The SBA believes all these designs can be implemented without creating subsidization of the RtR customers by the other NS POWER customers. Consistent with comments above, the SBA does not believe a major criteria in designing the market is Simplicity of Implementation, Simple and Readily Comprehensiveness, Predictability of Outcomes, and Minimum Practical Regulatory and Administrative Burden. The SBA is concerned that focusing on these proposed criteria can open the door to subsidization. A small business customers cannot absorb more costs than necessary to provide its service. The above proposed criteria[1] must be secondary to accurate renewable generating unit specific avoided cost determinations and incorporation in the tariff rates in a manner that prevents subsidization.

Disaggregated Option - The SBA favors this option for two reasons and would like to see it be the focus of implementation. This option provides the greatest guard against cross subsidization in that it identifies seven steps of the RtR transaction and proposes to develop tariffs for each step.[2]

[1] PowerPoint Presentation Nova Scotia Power Renewable to Retail Project Market Design White Paper, *Robert Cary & Associates*, October, 2014, Slide 6

[2] PowerPoint Presentation Nova Scotia Power Renewable to Retain Project Market Design White Paper, *Robert Cary & Associates*, October, 2014, Slide 8

1. Distribution Service Tariff (payable by the RtR customer)
2. Customer Load aggregation for OATT (LRS is the customer for this transaction)
3. Top-up charges when renewable generators fall short of load (LRS pays)
4. Spill & Imbalance charges to absorb mismatched generation to load (LRS pays)
5. Surplus energy Payment (LRS Pays)
6. Capacity Back-up tariff analogous to top-up energy (LRS Pays)
7. Embedded Cost Recovery for stranded costs

This option optimizes the proportion of total costs and the greatest number of the transactions involve the LRS, making it simpler for the RtR customer. The SBA endorses the objective; simplify for the customer but do not simplify the transaction.

Integrated Option - The SBA believes that this option which provides a single integrated delivery service tariff providing all of the services except for surplus energy and is paid by the customer is also acceptable. This option is not preferred because it will be the responsibility and the burden of the RtR customer to understand more transactions, since the costs are passed on directly to the RtR customer. The SBA is also concerned about this tariff being less real time and thus prone to be creating subsidization.

Hybrid Option - The SBA recognizes the validity of the hybrid but imagines that some compromising of principles during the implementation process is likely given all the moving parts.

Financial Option- The simplicity of the financial option[3] sounds quite intriguing. The SBA would not oppose this option. However it is less likely to be the market maker for RtR sales that it has proven to be at the wholesale level in places such as New England.

V. Summary

The SBA submits these comments hoping that the preferences and concerns expressed above will be seriously considered. This will help assure accurate implementation of the legislation in a manner acceptable to the small business community, those who want to purchase renewable energy and those who do not.

Thank you for allowing me to provide my comments on this matter.

Yours truly,

BLACKBURN ENGLISH

E.A. Nelson Blackburn, Q.C.

SMALL BUSINESS ADVOCATE

EANB/dlh

[3] PowerPoint Presentation Nova Scotia Power Renewable to Retail Project Market Design White Paper, *Robert Cary & Associates*, October, 2014, Slides 14-15

Nova Scotia Power

Renewable to Retail Project

Embedded Cost Recovery White Paper

Robert Cary & Associates Inc.

2nd December, 2014

Contents

1 Introduction

1.1 Purpose of this white paper

This white paper follows on from the Market Design White Paper dated 2014 10 02 and presented at the stakeholder meeting on 2014 10 09. Under two of the market design options (disaggregated and hybrid) it is necessary to consider Embedded Cost Recovery mechanisms. Under the other two, (integrated delivery tariff and financial) there is no stranding to be addressed[1] and therefore no need to consider Embedded Cost Recovery.

The purpose of this white paper is to provide to potential RtR generators, Licenced Renewable Suppliers, RtR customers, and NS Power and other stakeholders a common understanding of the context of, need for, and principles applicable to Embedded Cost Recovery mechanisms. Such mechanisms may be necessary for the recovery by NS Power of costs related to stranded assets, and in respect of deferred cost recoveries and credits, all in the context of a disaggregated market design or a hybrid market design.

The white paper also identifies a number of choices to be made in the design of Embedded Cost Recovery mechanisms.

1.2 Context for this white paper

The context for this white paper is the potential that a disaggregated tariff approach[2] as identified in the white paper on market design may, and is indeed likely to, lead to exit of certain retail customers from NS Power's supply, at least for the term of their commitment to take RtR supply. The exit of RtR customers from NS Power supply may result in the "stranding" of certain generation or other supply-related investments or commitments which have been or are being properly made by NS Power in fulfillment of its obligation to serve all customers including those who would now take RtR supply. The nature of such stranded assets and the associated costs are discussed in section 3 of this white paper.

[1] Under the integrated delivery service tariff, the RtR supply chain bears the NS Power full cost of service less those costs avoided by virtue of the RtR supply; stranded costs are by definition not avoided, so costs that might otherwise be stranded continue to be recovered under the integrated delivery servicer tariff. In the financial option, NS Power continues to charge its full service tariff, and provides an avoided cost credit to the generator, so there is again no financial stranding.

[2] As noted in section 1.1 of this white paper, Embedded Cost Recovery may be required under either the disaggregated tariff approach or the hybrid approach. For simplicity of language, only the disaggregated tariff approach is referenced here and in any subsequent sections.

In addition to the generation or other supply-related investments[3] that may be stranded, there are certain costs incurred by NS Power that would, through the normal rate-setting process, be charged to customers on a deferred basis. There may also be credits due to customers on a deferred basis through this same process. These are collectively referred to as deferred cost recoveries and credits. The charges or credits may take the form of rate riders, or they may be embedded in service rates. The customer share of amounts outstanding at the time of an RtR customer exit relate to service prior to such exit, and so are properly borne by or credited to the exiting customer. The nature and potential treatments of such deferred cost recoveries and credits are discussed in section 4 of this white paper.

Customers who elect to take RtR supply have a right, under conditions to be determined and in accordance with contractual arrangements that they will make with their Licenced Renewable Supplier (LRS), to return to NS Power supply at some future date. NS Power must maintain supply capability for such eventuality, and any supply maintained for this purpose would become "un-stranded" on RtR customer return to NS Power supply. A returning RtR customer should also not be subject to deferred cost recoveries and credits relating to NS Power generation or purchased supply during the duration of its RtR service. These issues are discussed in each of sections 3 and 4 of this white paper. Any decisions on such mechanisms will need to take account of the administrative burden they may impose relative to the materiality of the amounts involved.

1.3 The legislation in Nova Scotia

The Electricity Reform (2013) Act requires that RtR access be provided without harm to other customers. NS Power rates charged to other customers must therefore not include any incremental amounts arising from NS Power's provision of services in connection with RtR supply, or as a result of an RtR customer's exit from NS Power regulated supply.

The Public Utilities Act (1989) as amended provides that each public utility[4] be entitled to charge rates that recover reasonably and prudently incurred expenses as well as a just and reasonable return on its rate base[5]. Where expenses, including future commitments and rate-base assets, have been reasonably and prudently incurred, NS Power is entitled to their recovery, including the just and reasonable return on the rate base. This remains true when customers exit NS Power supply service in order to take RtR service. Under the Electricity Reform Act (2013) there can be no transfer of costs to remaining customers. It is therefore the exiting RtR customers who must remain responsible to bear embedded

---

[3] This white paper also addresses the potential for stranding of transmission or distribution assets, but any stranding of such assets is likely to be non-existent or small, depending on tariff design options selected.

[4] Which term includes NS Power.

[5] This is a brief paraphrase of the core of section 45 of the Act. Please refer for full detail to that section and the immediately preceding sections of the Act; the preceding sections relate to the various component elements of expenses and rate base.

cost amounts relating to assets or expenses that would otherwise not be recovered by NS Power as a result of the RtR customers exit.

1.4 Concepts of stranded assets, stranded capacity, stranded debt, embedded costs, etc.

It may be useful to discuss a number of closely linked concepts that are used in this white paper and referenced in discussion of other jurisdictions.

- The term "stranded asset" has a narrow meaning and has a range of generic uses. In its narrow meaning, an asset (such as a generating station) is stranded only if it has become fully redundant as a result of a change. The complete asset may be taken out of service, at which point its net book value[6] would be financially stranded.
- In the context of a market restructuring or similar event, and asset may be physically still useful in its entirety, but it may be partially stranded in a financial sense by the reduction of its value. The value realisable through competitive market prices may be less than that realisable through previously regulated rates. The impairment charge taken to reduce its net book value would be the financially stranded amount. In market restructurings the impairment charge is often reimbursed to the incumbent utility by funds raised though the issue of bonds, and those bonds repayments are then funded from a Competition Transition Charge ("CTC") or similar.
- In the context of the exit of some customers to take newly permitted competitive supply, it is likely to be part of the capacity of an asset or of a portfolio of assets that is stranded. There is probably no single asset that can be identified as being stranded by any particular customer exit. In a physical sense, it is that element of physical capacity or energy cost premium that is stranded. In a financial sense, it is the $ asset value of that physical capacity that is stranded.
- The stranded debt referred to in the Ontario context is really a special case of financial stranding arising on market restructuring. Because Ontario Hydro was so highly debt financed, all of the asset value impairment was offset by forgiveness (by the government agency OEFC) of the corresponding debt which was then described as stranded debt, pending its recovery as discussed in section 2.2 below.
- Embedded costs are the costs, including the reasonable return, associated with:
    - Capacity that is stranded,
    - Energy cost premiums that are stranded, and
    - Deferred cost recoveries (net of credits).

[6] Note that there would in practice be a more detailed accounting which would also include items such as decommissioning costs net of salvage revenues, staff terminations costs, and offset by any decommissioning accruals. This is beyond the scope of this white paper.

In the balance of this white paper, the term "stranded assets" is used in its broader sense, to include concepts of value impairment and stranded capacity in physical and financial senses, not necessarily linked to the redundancy of distinct physical facilities.

1.5 Capacity issues and IRP[7] references

To the extent that certain costs are recovered under other NS Power tariffs applicable to the RtR supply chain, they are not stranded and therefore do not need to be recovered through an Embedded Cost Recovery mechanism. This is particularly true of costs that relate to the maintenance of generation capacity necessary to fulfill NS Power's obligations for overall system adequacy, to provide backup service (particularly in respect of RtR wind generation) and to provide for return to NS Power service. Appendix A identifies some key issues and some examples of alternative treatments that could be applicable to different types of RtR generation resources. These discussions inform section 3 of this white paper.

As noted in the Market Design White Paper, it is assumed that RtR generators and LRSs would seek to match annual generation volumes to RtR customer volumes with a small surplus. This target surplus would be whatever quantity they themselves consider prudent to assure themselves of annual fulfillment of their compliance obligation. That surplus may also be expected to vary over time, reflecting the granularity of economical generation investments and the timing of customer uptake. The working assumption of this white paper is that the surplus will at any time be relatively small, and that it is not necessary to design the system to accommodate significant annual surplus generation by RtR generators.

Another working assumption of this white paper is that all RtR generation facilities would be classified as network resources connected to the grid under NRIS service[8], capable and committed (to the extent of their production capability at any time) to inject energy to the grid at NS Power's call. This would allow the resource to contribute to the fulfillment of NS Power System Operator's system adequacy obligations by way of partial self-supply in respect of the RtR load[9].

Some of these concepts are discussed further in Appendix A, which also includes illustrative models of capacity and energy numbers that are used for illustration in section 3, below.

---

[7] All references to the IRP are to the October 15, 2014 IRP Final Report as available at http://www.nspower.ca/site/media/Parent/20141015%202014%20IRP%20Final%20Report.pdf

[8] This is consistent with the IRP planned treatment of all new wind facilities to be developed under NS Power PPAs; ref IRP page 34 line 17. The assumed capacity value for such RtR wind generation is 17% of installed capacity, also in accordance with that same reference.

[9] This contribution of self-supplied capacity towards the NSPSO's overall system adequacy obligation is assumed to be scaled to the use of RtR generation to meet the RtR compliance obligation with an allowance for reasonable surplus over that minimum compliance requirement.

The IRP provides important context in three other respects:

- NS Power's reserve margin required to maintain system adequacy is 20%[10].
- The RES 2015 obligation on NS Power[11] is that 25% of net sales must be generated by renewable electricity. By 2020 this increases to 40% of net sales. NS Power has made the necessary commitments to achieve these requirements.
- No major generating capacity additions or contract commitments are necessary until those that may be required for use in the 2030's. The key planning and investment variable over the present planning horizon is in DSM[12].

1.6 Organisation of this white paper

1.6.1 Precedents for embedded cost treatments

Section 2 of this white paper provides background information on the precedents in other jurisdictions that may be relevant to embedded cost recovery in Nova Scotia.

1.6.2 Stranded Assets and associated costs

Section 3 of this white paper discusses the principles for the identification of embedded costs associated with assets that are potentially stranded, temporarily or permanently, by RtR customer exit from NS Power supply, and identifies such asset types and the associated costs.

1.6.3 Deferred cost recoveries and credits

Section 4 of this white paper discusses the principles for the identification of deferred cost recoveries and credits.

1.6.4 ECR options

Section 5 of this white paper discusses the options for the recovery of embedded costs, and the issues to be considered in selection of an approach in the RtR project, including in respect of return to NS Power service.

1.6.5 Consultation questions

Section 6 of this white paper identifies certain questions for stakeholder consideration and response in the consultation process.

---

[10] Ref IRP page 75 line 15.

[11] Ref IRP page 33.

[12] My understanding of the IRP executive summary.

2 Experience elsewhere

2.1 Principles

In order to minimise rates, the utility rates in non-competitive environments are typically set without regard to risk of customer bypass[13]. If historical rates had been set with a view to a monopoly utility bearing such risk, those rates would be expected to reflect a higher just and reasonable rate of return for the utility to compensate for such risk, and thus a higher cost to customers. Absent historical rates that incorporate such risk based returns, the utility has not been compensated for bearing such risk. Legislators and regulators have therefore recognised that utilities should not suffer loss in respect of commitments made or liabilities incurred under a prior regime due to the change in regulatory regime from a non-competitive to a competitive environment.

The US Federal Energy Regulatory Commission summarised this well in its order 888-A, where it is noted[14] that *"[i]f a former wholesale requirements customer or a former retail customer uses the new open access to reach a new supplier, the utility is entitled to seek recovery of legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer."*

There are two broad categories of historical examples where this principle has been applied. Where there has been a complete restructuring of a wholesale electricity market to introduce competition and pool-based pricing, the regulatory authorities have established a non-bypassable Competition Transition Charge (CTC) with the purpose of funding compensation (or equivalent debt relief) to utilities for the loss of asset value. This category includes Ontario's Debt Retirement Charge and the CTCs in US energy markets, which are discussed in sections 2.2 and 2.3. The second category arises where market restructuring has been less fundamental, so that the utility's default service customers do not benefit from the change. This category includes New Brunswick, other Canadian provinces, and certain US jurisdictions, all as discussed in sections 2.4 to 2.6.

2.2 Ontario

Until restructuring of the electricity market, starting in 1999, the government-owned Ontario Hydro and each of the municipally owned electricity distribution commissions had been operated on a not-for-

---

[13] Customer bypass is used in a generic sense here to mean any avoidance of rates that have been designed to be universally payable. Physical customer bypass most commonly arises when generation and load are directly connected, bypassing meters that determine charges in respect of grid services. Customer bypass includes exit for purposes of taking a competitive supply, but does not include exit for reasons of moves, business closing etc.

[14] Note that FERC's Order 888-A is titled: "*Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*". This citation is from page 203 in part II of the order at http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8p2-000.txt

profit basis and charging rates based generally on whatever costs they incurred. The Ontario Energy Board provided a degree of Ontario Hydro rate oversight. In 1999 Ontario Hydro was restructured into the generation business (Ontario Power Generation), the transmitter and rural distributor (Hydro One), and the system operator. The generation assets were revalued on the basis of what they could be used to earn in the restructured market. Some $ 15 billion of generation asset value was stranded by the restructuring of the market, and the successor entities in aggregate were relieved of the debt associated with this plus an additional $ 5 billion of liabilities in respect of power purchase agreements priced above new market price expectations. Ontario Hydro / OPG was relieved of some $ 20 billion of debt and liability that had been accumulated but was not, in respect of the generation component, supportable by the reduced valuation of the generation and contracted procurement assets. The repayment of this stranded debt is ongoing and is achieved through three streams, all ultimately funded by Ontario customers and non-bypassable: the obvious stream is the Debt Retirement Charge of $ 7 / MWh added to all customer bills; in addition, the transmission and distribution rates were increased to allow Hydro One and municipal distributors to earn profit and make payments in lieu of taxes; and OPG was also structured to make a profit (and has subsequently been subject to rate regulation recognising profit) so that payments in lieu of taxes can be used to pay down the stranded debt.

To summarise, restructuring triggered the stranding of $ 20 billion of asset value, but did not render any assets physically redundant. In effect the Province bought down the value of assets at the time of restructuring, and then used the various mechanisms described above to service the debt incurred to do this.

Ontario's Global Adjustment mechanism was introduced in 2005. It is quite separate from the Debt Retirement Charge and from the original restructuring[15]. In addition to covering historic investments, it covers new investments undertaken for system adequacy and those for the furtherance of government policy. The costs incurred for system adequacy are more akin to backup service charges, and the costs incurred for other government policy objectives are more akin to system benefit charges. These elements are all blended in the single Global Adjustment. The Global Adjustment therefore provides a useful example of non-bypassable charges in support of system adequacy and reliability, but not particularly as a precedent for consideration of embedded cost recovery in the context of a transition from a non-competitive to a competitive environment.

---

[15] The costs and credits charged to consumers through the Global Adjustment comprise costs of conservation programs, costs / credits to the extent that OPG's regulated electricity generation rates are above or below market rates, and contract payment amounts to generators in respect of all contracted generation supply. Part of the OPG portion is the successor to a rebate program in effect at market opening (quite separate from the Debt Retirement Charge). A portion relates to the out of market cost of legacy Ontario Hydro PPAs (thus relieving this liability from debt retirement). The majority however is completely new, and relates to increased OPG regulated prices and to new contracts including for nuclear, gas fired, hydroelectric, wind, solar and biomass generators.

2.3 US market wholesale restructuring

Competition Transition Charges were typically established at the time of market restructurings that took place in the late 1990s or early 2000s. Most of the affected utilities were (and still are) investor owned, so there was not a government entity to step in and carry the stranded debt arising from asset devaluation on market opening. Instead, the more normal mechanism was for the utility to establish a special bond program. Bonds would be issued to buy down the stranded asset value, with legislative or regulatory provisions for the funding of debt service through a non-bypassable rate adder, which may in some cases become a credit. Examples are California, Texas, New York and New England. In the last three of these the rate adder is still in effect and is listed on customer bills.

2.4 New Brunswick

The New Brunswick Open Access Transmission Tariff (OATT) provides competitive supply access for municipal distributors and large transmission connected) industrial customers. It follows the pattern established by FERC in its Order 888. The OATT (October 2013) states in section 26, and repeats in section 34.5

> *26 STRANDED COST RECOVERY*
>
> *The Transmission Provider or Transmitters may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff. However, the Transmission Provider or Transmitter must separately file any specific proposed stranded cost charge with the Board.*

No filing had been made by the end of 2011[16], and no filing is on record for any such proposal since then. Inclusion in the OATT in this way would appear to reflect intent of adherence to the FERC principles relating to stranded costs as noted in section 2.1 above. But without any filing, this is not tested.

2.5 Other Canadian Provinces

Only Alberta allows retail access, and the default service rates provided by regulated utilities are required to reflect the market price; in particular for residential consumers, the price must be based on a portfolio of one month (financial) contracts procured not more than four months in advance according to expected demand. Any element of stranding is thus very short term, limited by the forward contract time horizon. Potential customer exit is recognised at the time of procuring the supply portfolio, and any stranding that does take place is naturally unwound within a month or two.

[16] 2011 state of the market report as reported by BC Hydro in its response, prepared by E3, on Large Load Interconnection and Retail Access Policies.

While other Canadian Provinces have OATTs that provide non-discriminatory transmission access for wholesale customers, none have retail access and, except possibly for Saskatchewan[17], none have experienced wholesale customer exit that would warrant the determination of ECR or equivalent mechanisms.

2.6 US market retail access

Many US states within active pool-based regional markets require that the default supply service be procured by the regulator[18] (or under the regulatory regime) by a competitive auction process, with a defined time frame. The energy supply obligation is separate from the distribution service function. Bidders in such default supply auctions have the opportunity to assess the customer exit risk, and more importantly, to use the ongoing competitive market and related forward contracting to true up or down as actual outcomes may diverge from expectations. Embedded costs are not an issue in such a regime.

In states where default supply is the obligation of the distribution wires owner, it generally follows a cost of service model, recognising that much of the supply cost will be incurred as market prices or long term contracts with generators, together with transmission costs. Bills are frequently disaggregated to show supply, transmission, distribution, and any non-bypassable wholesale CTCs, renewable portfolio costs, or system benefit charges separately. To the extent that the generation asset values have already been written down to reflect the prices that can be secured in the market in which they operate, the market itself provides a good hedge in respect of over- or under-commitment of supply until the opportunity to adjust contract volumes. The BC Hydro / E3 report cited above (footnote 16) identifies utilities (Pacific Power and Portland General Electric) where there is a transition adjustment which represents the difference between the “freed up” energy cost (otherwise known as the avoided cost) and the regulated rate. These are equivalent to ongoing Embedded Cost Recovery mechanisms. Review of Portland General Electric rates indicates values up to and in some cases somewhat above 2c / kWh. Public Service of New Hampshire includes an ongoing stranded cost recovery charge in respect of exiting customers in its published rate tables (generally up to 2 c / kWh).

---

[17] SaskPower provides a Business Practice in respect of stranded cost recovery in the event of planned exit by a wholesale customer. This BP provides for individual assessment in order to determine the exit fee applicable to any wholesale customer considering exit from SaskPower’s bundled supply. It has not been possible in the preparation of this white paper to determine whether there has been any actual exit under these provisions.

[18] I.e., the regulator will arrange an auction process among energy companies, and the winner has the right and the obligation to meet all retail customer default supply requirements for a defined period at its quoted price(s).

3 Stranded assets and associated costs

3.1 Generation and supply

3.1.1 Scope

Given that RtR suppliers will construct and interconnect generation to the transmission or distribution system, and will utilise service over that transmission and distribution system for delivery of power, it is evident that it is principally the generation assets and purchased supply commitments of NS Power that are at risk of being stranded. Stranded asset discussion will therefore focus first on NS Power generating capacity and then on other supply commitments.

These other supply commitments are in the form of PPAs undertaken for fulfillment of the RES obligation or other purposes recognised by the UARB as appropriate for inclusion in regulated revenue requirements. Such other commitments can also include long term import commitments which may have fixed (capacity based) and variable (energy based) components or guaranteed energy quantities.

It is assumed in general that <u>energy</u> related costs are not stranded, as the energy production of fossil generation can be reduced to match need. The risk however is that NS Power's committed resources and contracts for the supply of renewable generation to meet RES obligations cannot be reduced. As NS Power's net electricity sales are reduced by RtR customer exit the RtR supply will in effect displace fossil energy with a lower marginal cost than the committed cost of renewables. In this scenario, the premium cost associated with the RES share (25% rising to 40%) of NS Power's supply is effectively at risk of being stranded. NS Power customers cannot be charged for the consequent increase in the renewable share of NS Power's portfolio. This issue needs to be considered in conjunction with any adjustments to either the RtR compliance obligation, or the NS Power RES obligation. That issue is addressed in a separate supplementary note[19]. Pending consideration of that issue, the white paper thus focusses on the stranding of capacity and capacity-related costs, essentially the investment costs and fixed operating costs. Section 3.2 includes a brief discussion of the embedded RES compliance premium costs which are potentially stranded.

3.1.2 To identify stranded generation and other supply

The NS Power generation asset and contracted supply portfolio can conceptually[20] be divided among three categories:

a) used and useful in the provision of service to NS Power continuing full service customers and in the provision of backup (capacity) service and top-up (energy) service to wholesale customers.

---

[19] Depending on decisions made as discussed in that note, energy ECR may or may not be applicable.

[20] Individual assets are unlikely to be identifiable in any particular category as the RtR customer base may vary in very small increments, whereas the generation portfolio comprises individual assets of larger size.

All costs are recovered through the rates charged to NS Power full service customers and wholesale customers respectively.

b) used and useful in the provision of backup (capacity) service and top-up (energy) service to the RtR supply chain.

All costs should be recovered through the rates charged to the RtR supply chain.

c) redundant but required to be maintained for the event of customer return to NS Power service.

Category (c) assets are stranded, as there is no avenue of cost recovery other than through an ECR mechanism.

3.1.3 Assets made redundant but still required

RtR generation connected to the grid under NRIS service effectively self-supplies a portion of the system capacity adequacy requirement. This displaces the need for equivalent NS Power capacity, and it thus makes redundant that NS Power capacity, in effect stranding the corresponding asset value. The costs and returns associated with that displaced capacity are not recoverable under the backup or any other existing tariff. While NS Power has an obligation to mitigate any such loss, the portion that cannot be mitigated is properly the subject of an ECR charge.

Any permanent mitigation that NS Power might seek to undertake is limited by NS Power's obligation to recognise its obligation to serve any RtR customers who choose to return to NS Power service, and NS Power's obligation to include such eventuality in its planning. Unless the required notice for return to NS Power service is long enough to allow for alternative resource procurement, NS Power would be required to maintain existing capacity. Temporary mitigation measures (such as deferral of DSM expenditures or export sales of capacity and energy) may be possible, but overall NS Power is still required to maintain such assets.

Using the illustrations in Appendix A, the quantities of backup capacity required and NS Power stranded capacity (before mitigation) would be:

		wind	biomass
Σ customer peaks	MW	50.0	50.0
installed capacity	MW	76.5	33.5
dependable capacity	MW	13.0	33.5
backup requirement	MW	35.0	14.5
NS Power stranded	MW	13.0	33.5
Note: refer to Appendix A for detail			

3.1.4 Putting a value on these quantities

The appropriate valuation of these stranded assets is the revenue loss by NS Power. This represents the embedded cost that would otherwise have been recovered through rates, less any mitigation that NS Power can achieve.

The revenue loss is represented by the capacity cost element built into NS Power customer rates[21]. This is based on allocation of the total pool of capacity costs, effectively on an average basis across customers. The basis for determining the stranded capacity cost per MW of capacity requirement is therefore the average capacity cost, not any particular marginal capacity cost. The rate per MW of dependable capacity stranded would therefore be the total revenue requirement classified as demand related, divided by the total dependable capacity[22]. Any mitigation would be offset against this.

The duration over which the quantum of permanently redundant MW would decline to zero can in principle be assessed on the basis of the integrated resource planning that underpins any rate application.

3.1.5 Purchased supply commitments

Purchased supply commitments (e.g. as PPAs and through the Maritime Link) are part of the generation and supply portfolio. The PPAs themselves will most likely protect the generator from being stranded as a result of RtR displacement. In addition, the legislation requires that RtR be implemented without harm to existing generators. These generators themselves will not be subject to any physical stranding. However, NS Power's commitments to those generators may be financially stranded. This type of financial stranding will be exhibited through the non-recoverability from departing RtR customers (absent an ECR) of any energy cost premium associated with these commitments, as discussed in the context of RES obligations in section 3.2 below. No other special consideration of their capacity is therefore necessary.

3.1.6 Fixed operating costs

Fixed operating costs are naturally included in the capacity-related revenue component that forms the basis for valuation of the MW stranded. They do not therefore require separate consideration.

---

[21] Note that rate design allocates charges between fixed charges, demand charges and energy charges. That cost allocation between demand and energy rates for rate design does not necessarily correspond to the basis on which costs are incurred (e.g. particularly for residential and similar customers whose rate is split between fixed and energy only), nor is the customer demand determinant the same as the customer share of the adequacy requirement that is referenced here.

[22] There are alternative approaches to valuing capacity, particularly in a fully competitive market environment. The cost of new entry of a gas fired simple cycle combustion turbine would be a common example (the Equivalent Peaker method). That Equivalent Peaker approach would not however reflect the actual revenue foregone in respect of the capacity stranded in Nova Scotia.

3.2 RES compliance premium costs

In the case that the RtR compliance obligation remains at 100% of RtR customers annual energy consumption[23] then any premium cost of energy procured for RES compliance purposes in respect of the RtR customer load is stranded. NS Power's revenues in respect of the RtR energy quantity are reduced by the average rate, including such RES-compliance resources. Its costs are reduced by the probably lower marginal costs of the avoided fossil fuelled generation. The difference between that average rate and those marginal costs is stranded, and is appropriately the subject of Embedded Cost Recovery.

3.3 Transmission

To the extent that a RtR generator is connected directly to the transmission system, all production will naturally flow through the transmission system at all times, and so there would be no reduction in overall use of the transmission system, so properly designed tariffs (and in particular properly designed aggregation of metering to virtual delivery point values) will avoid any stranding.

It is also necessary to consider the case where RtR generation is located in the same distribution zone as RtR load. There will be times when RtR generation and load are both operating, so that the use of the transmission system will not include that supply within the same distribution zone. There will be other times when the RtR generator is on outage or has no fuel, and all supply is sourced from NS Power generation under the back-up and top-up arrangements. Those back-up and top-up arrangements cover the costs of the generation component of such supply as injected into the transmission system; delivery over the transmission system is also required and would be part of the OATT service. The requirement for transmission system delivery capacity to that distribution zone is not reduced by the location of RtR generation within the same zone as load. The transmission charge should therefore not be reduced to reflect such location within the same zone. The transmission charge determinant in respect of RtR load should therefore be calculated on the basis of the load alone, without any offset for RtR generation located in the same zone. In this framework, there is no stranding of transmission assets.

Only if there were sufficient RtR supply diversity within a distribution zone would the peak transmission delivery capability required to that zone be reduced.

In the event that there was sufficient diversity[24] of RtR supply within a particular distribution zone to assure a certain level of supply at all peak periods, then the peak transmission delivery capability required to that zone could be reduced, and there would be an argument for a reduced OATT charge

[23] See section 3.1.1 for introductory discussion of this issue.

[24] Such diversity would require diversity of fuel types as well as diversity of connection points, and is extremely unlikely in the context of RtR generation in any reasonable planning horizon.

determinant. That would effectively strand some of the transmission asset. The ECR required would exactly offset the transmission charge reduction[25].

In order to avoid the complexity of assessing ECR for transmission, it is proposed that financial stranding of transmission be avoided simply by setting the transmission charge determinant on a gross RtR load basis, ignoring any co-location within the same distribution zone. Should sufficient diversity of zonal supply emerge, then this could be reconsidered.

3.4 Distribution

Co-location of RtR generation behind an RtR customer meter is not contemplated[26]. Distribution assets are therefore not expected to be stranded. Nor due to the radial nature of distribution systems would any amount of RtR generation likely displace any required investment in distribution.

The RtR framework can co-exist with the present net metering arrangements, as those net metering arrangements for low impact renewable generation do not permit any sales from one entity to another. The two arrangements are mutually exclusive.

3.5 DSM

To the extent that all customers connected to NS Power's transmission or distribution systems are eligible for centrally funded DSM services, they would be beneficiaries of those DSM services and thus properly subject to charge for those services.

To the extent that RtR customers become ineligible for DSM services they would cease to be beneficiaries and should not bear ongoing cost, but should bear deferred costs associated with the period during which they were eligible.

The inclusion or exclusion of RtR customers from centrally funded DSM programs would appear to be a matter of policy and of practicality. From a practical perspective, to the extent that any programs are delivered through public channels (as opposed to utility-customer communication channels) they are naturally available to all.

The working assumption for this white paper is therefore that RtR customers will continue to be served by centrally funded DSM programs, and will thus bear their share of such program costs. DSM is therefore not a matter for consideration of ECR.

---

[25] The only exception to this would be if there was sufficient load growth in a distribution zone that the presence of diverse local generation could defer or avoid transmission or transformer station upgrade. This combination is even less likely in the context of RtR generation in any reasonable planning horizon.

[26] Were it permitted it would simply, in financial terms, strand generation, transmission and distribution assets, requiring an ECR charge equivalent to the charges avoided for those NS Power services.

4 Deferred costs and credits

4.1 Rate rider items

NS Power tariffs presently include two riders:

- The DSM Cost Recovery Rider

  Prior to 2015 DSM costs, whether current or deferred, were recovered through a Rider. For 2015 and forward the recovery of these costs is yet to be determined. But as noted in section 3.5, the DSM cost recovery is assumed to be part of the ongoing tariff structure applicable to the RtR supply chain. So DSM costs would not in that case be stranded by RtR customer exit. Were that assumption not to be fulfilled, then deferred DSM cost recoveries could be stranded and the subject of an ECR mechanism.

- The Fuel Adjustment Mechanism ("FAM") provides for the true-up of the variances between FAM amounts recovered from customers and the actual fuel costs incurred by the Company: the Actual Adjustment (from the immediately prior year) and Balance Adjustment (from previous years).. Each component of the FAM could be a charge or a credit.

4.2 Embedded deferrals

Embedded deferrals are those for which cost recovery is embedded in NS Power rates[27].

These deferrals arise from a number of specific causes, some of which may be attached to particular aspects of NS Power's activities (generation & supply, transmission or distribution) but several of which appear to be of a more corporate nature. To the extent that they are as a matter of principle or policy deemed to be recoverable through a (non-bypassable) distribution tariff or OATT, none of them is stranded by RtR customer exit. To the extent that any is treated as a deferred cost of supply (either directly or by proportional allocation) it would be stranded and appropriately subject to ECR.

It is assumed that considerations of materiality and simplicity would support a preference to treat all such costs as attached to non-bypassable distribution service, so that none would be stranded.

[27] Refer to NSPI Fuel Cost Deferral Hearing (NSUARB M06475), Request IR 4 and response which lists these items and their status.

5 Options for Embedded Cost Recovery mechanisms

5.1 Types of ECR

Based on the discussion in previous sections of this white paper, there are several probable or potential sources of ECR to be considered under the disaggregated tariff option:

- Generation capacity: near certain; see section 3.1
- RES energy premium; probable; see section 3.2
- Transmission: not unless bypass is permitted; see section 3.3
- DSM: not unless DSM program exit is permitted; see section 3.5
- FAM balance: probable; see section 4.1
- Embedded deferrals: only to the extent that these are attached to the supply portion of the disaggregated tariff, as opposed to the transmission or distribution portions; see section 4.2

Mechanisms should therefore be designed primarily to address ECR with respect to generation capacity, RES energy cost premium, and FAM balances.

5.2 Generic options

There are two ways to provide for recovery of stranded costs in the relevant categories:

- Ongoing Embedded Cost Recovery charges or credits (Retail Access Adjustments); and
- One-off Embedded Cost Recovery charges or credits (Exit and Re-entry Adjustments).

5.2.1 Retail Access Adjustments

A Retail Access Adjustment (“RAA”) is an ongoing monthly charge, based on the applicable demand or energy billing determinants, that provides for the appropriate Embedded Cost Recovery over the period of RtR supply. The RAA would be a rate presumably requiring approval by the Board.

In principle this is the most appropriate way, for the present at least, to determine the ECR charge for stranded capacity or RES premium. There may be opportunities that vary over time for NS Power to mitigate certain losses, but there is in the medium term at least, no natural decline in the stranded amount of capacity or RES premium that is caused by the duration of exit. This could change in the long run as NS Power can take advantage of RtR customer exit to avoid new generation investments or supply contract commitments or extensions.

A single set of Board approved RAA rates would apply to all RtR customers in the applicable year irrespective of when they had first taken RtR service.

5.2.2 Exit and Re-entry Adjustments

An Exit Fee is a single lump sum amount charged to the exiting customer (or to the LRS) at the time of transfer to RtR service. It would provide for the recovery at that time of the estimated total present value of the amounts stranded by that customer exit. Any Exit Fee would presumably be a rate requiring approval by the Board.

The Exit Fee is well suited to dealing with a deferred cost balance item such as the FAM balance, but it is more challenging to estimate the lump sum present value of ongoing stranded costs.

Inasmuch as an exiting customer should be responsible for (or receive credit for) their share of an item such as the FAM balance, so a returning customer should not be responsible for balances outstanding at time of return.

It is also necessary to consider how to treat returning or even re-exiting customers with respect to any exit fee assessed to represent the present value of ongoing stranded costs.

5.3 Considerations in selecting options

5.3.1 General considerations

In selecting whether to adopt an RAA approach, an Exit Fee approach, or a combination, it is appropriate to consider:

- The approach should be transparent and fair; the overview and rate approval by the Board should provide assurance of this.
- The approach should be comprehensible and as predictable as possible.
- The approach should avoid undue administrative complexity.

5.3.2 Customer switching / commitment period / notice period / partial service

The approach may be further affected by:

- Settlement arrangements (are ECR charges settled by customers or by the LRS)
- Technology issues and the relationship among for instance backup charges and ECR charges[28]
- Minimum commitment periods and minimum notice periods for switching
- Minimum notice periods for normal return to NS Power service, and conditions attached to shorter notice return

And the approach adopted may have an impact on the way that RtR supply is marketed.

5.3.3 Other considerations

As the design progresses, there will be a number of issues to be addressed. Questions identified to date include those relating to growth in the load of individual RtR customers:

- What is NS Power's obligation to supply the larger load of such a returning customer?
- How does this interact with the notice provided for such return?
- How do these interact with the methodology selected for the ECR (RAA or exit fee)?

[28] The individual charge items may vary according to the technology of the RtR generator, but there may be offsets among for example the backup charge and the capacity stranding charge that could argue for equivalent treatment.

6 Consultation questions

The following questions are put forward for stakeholder consideration:

Section 1.5

It is assumed that RtR suppliers will seek to target generation of a small surplus over customer load requirements in order to assure themselves of compliance. Is this valid? What level of surplus should be expected?

It is assumed that RtR suppliers would arrange for connection of their generation facilities as network resources connected to the grid under NRIS service, capable and committed (to the extent of their production capability at any time) to inject energy to the grid at NS Power's call. This would enable them to self-supply a portion of the capacity required to support RtR load. Is this valid? What issues or concerns arise from this? **[NTD NSP agrees with the assumption and would like the system operator to confirm.]**

Section 5.1

Are there any other categories of ECR that should be considered?

Section 5.2

Are there any other ECR options that should be considered?

Section 5.3.1

Are there any other considerations in selecting an ECR framework or frameworks?

Section 5.3.2

Can stakeholders indicate what they would consider reasonable design assumptions in each of the areas listed?

Section 5.3.3

Other considerations proposed by stakeholders?

Appendix A; Capacity issues

Purpose of this Appendix

The purpose of this appendix is to describe the capacity obligations that have to be satisfied by NS Power, and how these obligations impact the design of certain rates that would be required under the disaggregated tariff market option, and how those interact with the need for ECR in respect of capacity.

The appendix uses examples that are also referenced in the text of this white paper.

Assumptions underlying this discussion

The NSPSO is responsible under its arrangements with its NPCC Reliability Coordinator (New Brunswick Power System Operator) to ensure that it plans for supply adequacy of the Nova Scotia electricity system, and this obligation is fulfilled by planning and if necessary building or procuring sufficient generation to meet the forecast design peak load plus a 20% reserve margin.

The discussion addresses requirements to serve firm (non-interruptible) load customers.

NS Power retains the obligation to serve returning RtR customers on reasonable notice.

Model RtR customer and generation parameters

The starting point for the discussion is an illustrative model of an RtR customer portfolio.

- This portfolio comprises many customers. The total of their individual peak demands is 50 MW.
- Because of their diversity, their contribution to the overall system peak demand (the coincident peak) is 40 MW.
- In order to provide for system adequacy, the total dependable firm capacity requirement to serve this load is 40 MW + 20% reserve margin = 48 MW.
- The minimum coincident load is 15 MW.
- Each customer has an individual load factor of 50%, so their total annual energy consumption at the customer meters is 50 MW x 8760 hrs x 50% = 219,000 MWh.
- The average loss factor over the transmission and distribution systems is 5%, so the RtR generation that must be injected to meet the compliance obligation in respect of this load is 105% x 219,000 = 229,950 MWh.

This is summarised in the following table:

RtR customer parameters				
Sum of non-coincident peak demands		50	MW	illustration input
Contribution to system coincident peak		40	MW	illustration input
Reserve margin required	20%	8	MW	NS Power reserve margin
Total adequacy obligation		48	MW	
Minimum coincident load		15	MW	illustration input
Average customer load factor		50%		illustration input
Total annual energy consumption		219,000	MWh	
Average T&D loss factor (% of delivery)		5%		illustration input
Total annual energy injection requirement		229,950	MWh	

Were this to portfolio to be served by a typical wind generation, the illustrative generation requirements are:

- It is assumed that the RtR generator / LRS would seek to establish a small surplus generation quantity in order to assure itself of 100% compliance in each year. This margin is illustrated as 2%, so that the target annual production is 229,950 MWh x 102% = 234,549 MWh.
- It is assumed that the wind generation portfolio has a production factor of 35%, so that the required wind installed capacity is 234,549 MWh ÷ 8760 hrs ÷ 35% = 76.5 MW
- The maximum spill potential = 76.5 MW minus the minimum load of 15 MW = 61.5 MW.
- The dependable capacity contribution is 17% of the installed capacity (assuming NRIS connection) which is 13.0 MW.
- The total dependable firm capacity required to be available to the system operator is 48 MW, so the RtR supply chain will be required to purchase 48 – 13 = 35 MW of capacity under backup service.

This is summarised in the following table:

NRIS Wind generator example			
Planned surplus generation	2%		illustration input
Target annual production	234,549	MWh	
Production factor	35%		NS Power typical
Installed capacity	76.5	MW	
Maximum spill	61.5	MW	= capacity - min load
Dependable capacity contribution	17%		IRP
Dependable capacity contribution	13.0	MW	= capacity x contribution %
Backup capacity obligation	35.0		= adeq oblig'n - dep cap'cty

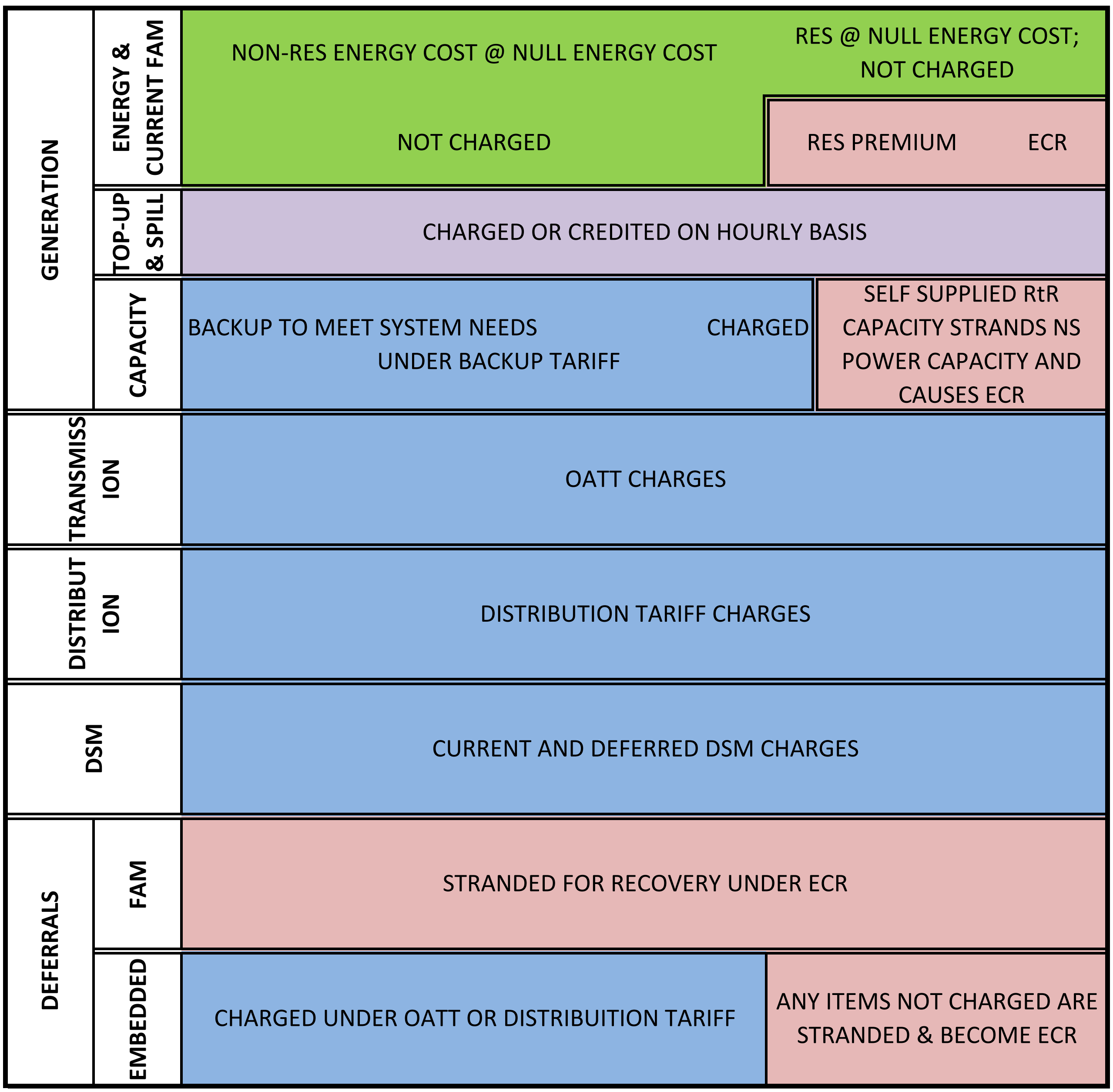
The equivalent information for a biomass facility is shown in the following table:

NRIS Biomass generator example			
Planned surplus generation	2%		illustration input
Target annual production	234,549	MWh	
Capacity factor	80%		NS Power typical
Installed capacity	33.5	MW	
Maximum spill	18.5	MW	= capacity - min load
Dependable capacity contribution	100%		IRP
Dependable capacity contribution	33.5	MW	= capacity x contribution %
Backup capacity obligation	14.5		= adeq oblig'n - dep cap'cty

(A) NS POWER RES OBLIGATION APPLIES TO ITS CUSTOMER LOAD ONLY

RtR OBLIGATION 100%

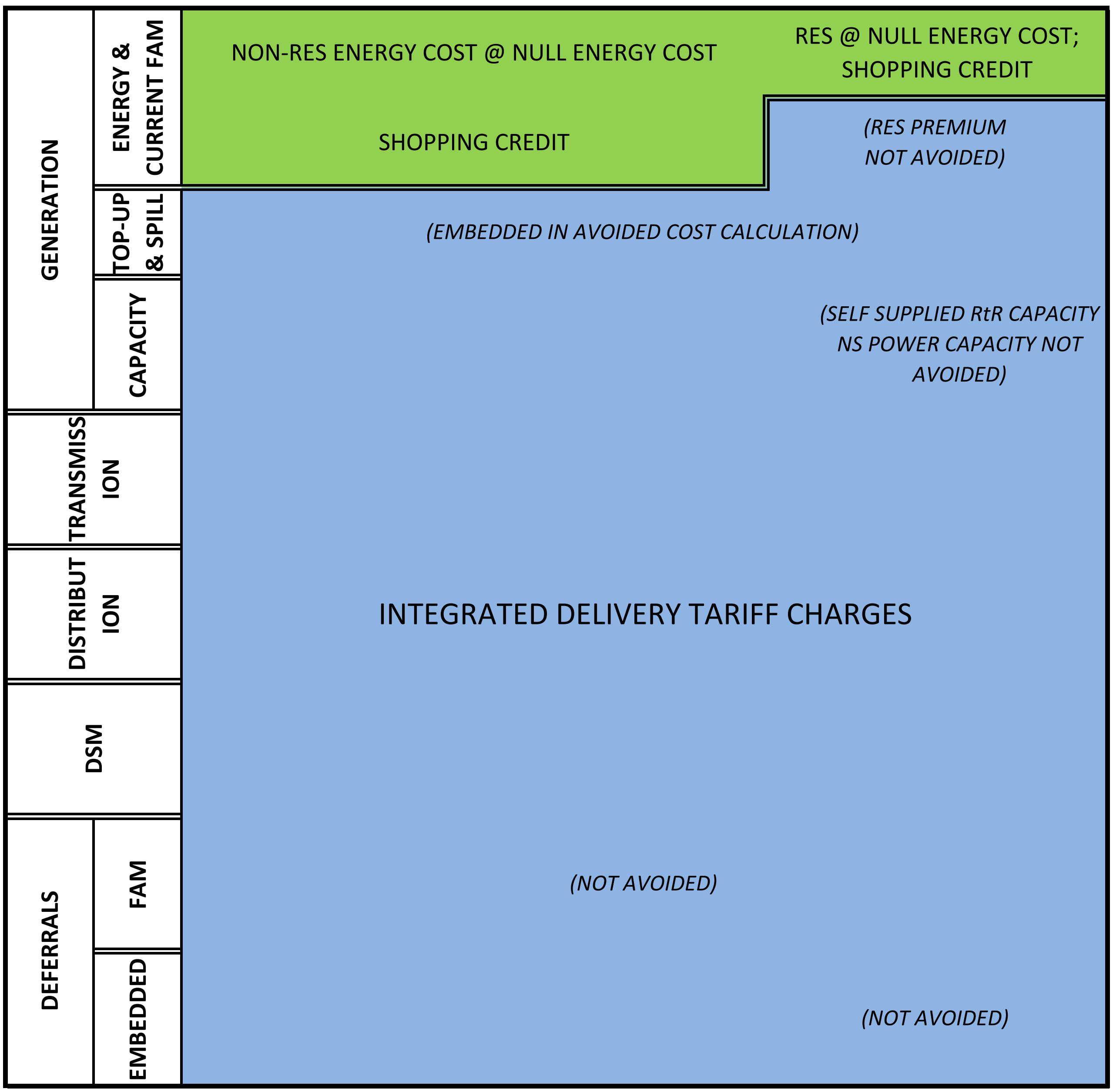
1. DISAGGREGATED TARIFF OPTION



(A) NS POWER RES OBLIGATION APPLIES TO ITS CUSTOMER LOAD ONLY

RtR OBLIGATION 100%

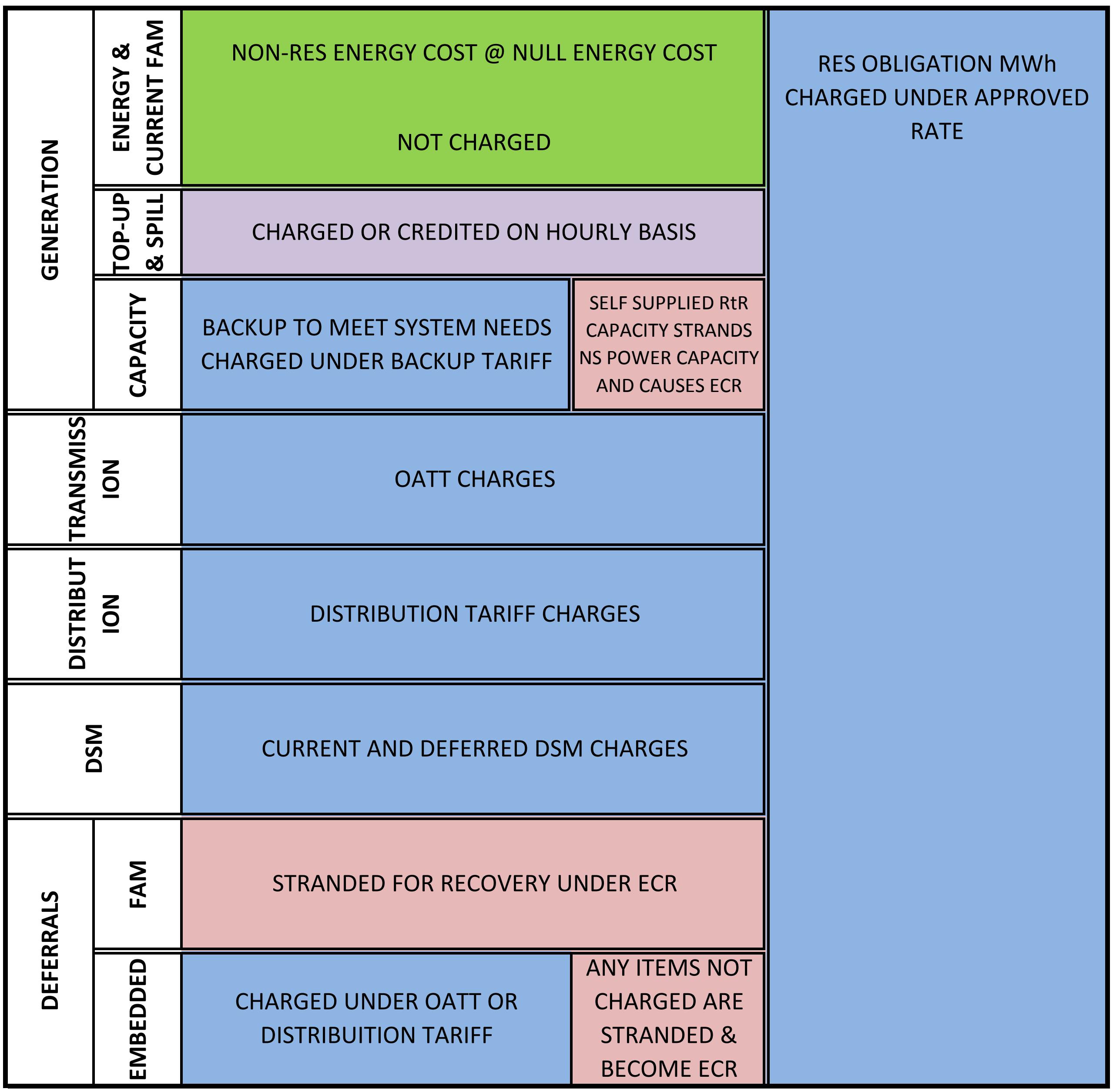
2. INTEGRATED DELIVERY TARIFF OPTION



(B) NS POWER RES OBLIGATION APPLIES TO ALL NS LOAD

RtR OBLIGATION REDUCED

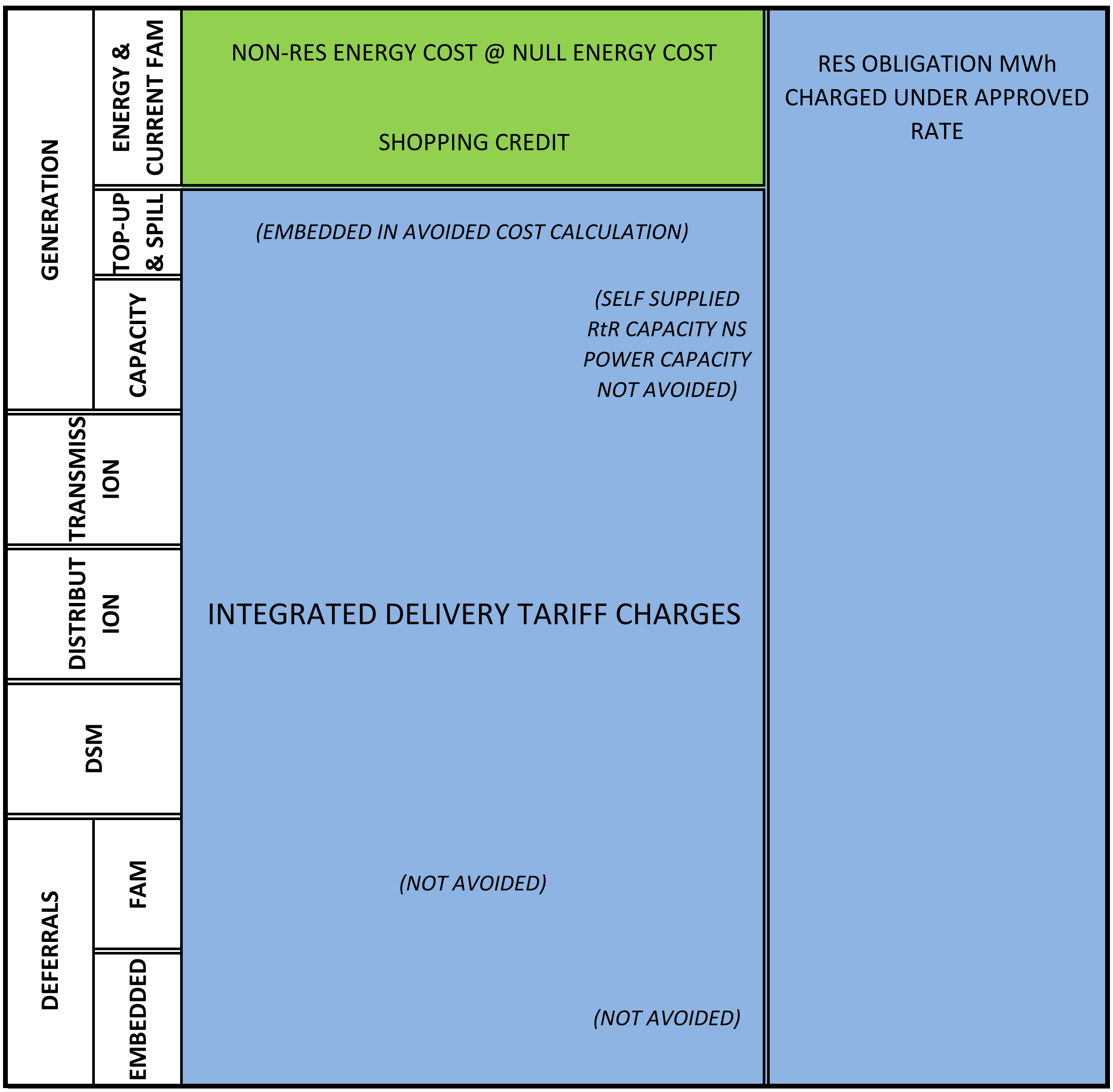
1. DISAGGREGATED TARIFF OPTION



(B) NS POWER RES OBLIGATION APPLIES TO ALL NS LOAD

RtR OBLIGATION REDUCED

2. INTEGRATED DELIVERY TARIFF OPTION



Nova Scotia Power

Renewable to Retail Market Opening Strawman Report

December 5, 2014

TABLE OF CONTENTS

1.0 INTRODUCTION

The NS Electricity Reform Act (the Act) was enacted on December 12, 2013. The Act enables NS Power's retail customers to purchase renewable low-impact electricity generated in Nova Scotia from licensed competitive suppliers. The Act stipulates that NS Power shall develop in consultation with stakeholders, and file with the NS Utility and Review Board (the Board) for approval, any new or amended tariffs, procedures and Standards of Conduct that are necessary to facilitate the purchase of renewable low-impact energy. The Regulations require that NS Power submit its application to the Utility and Review Board by September 1, 2014.

NS Power and Stakeholders have established Terms of Reference[1] for the development and implementation of a framework in Nova Scotia for competitive renewable electricity supply to retail customers. The Terms of Reference describes the scope of work as follows:

> As set out in section 3G(1) of the Electricity Reform Act (2013), NS Power is directed to develop in consultation with stakeholders, and file with the Board for approval, any new or amended tariffs, procedures and standards of conduct that are necessary to facilitate the purchase of renewable low-impact energy including:
>
> a) a new or amended open access transmission tariff (OATT);
> b) a distribution tariff;
> c) a new or amended backup/top-up service tariff;
> d) a new or amended non-dispatchable supplier spill tariff;
> e) new or amended interconnection procedures;
> f) new or amended market rules; and
> g) any other tariffs, procedures or standards of conduct prescribed by the regulations or that the Board requires Nova Scotia Power Incorporated to develop or amend in order to facilitate the purchase of renewable low-impact electricity.

[1] The Project Terms of Reference were developed with stakeholder consultation and published on the NS Power website, http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/regulatory-initiatives/renewable-to-retail.aspx.

In addition, the Terms of Reference contain the following criteria to guide the solution:

a) Customers of NSPI and persons who are independent power producers or hold feed-in tariff approvals are not to be negatively affected if some retail customers choose to purchase renewable low-impact electricity from a retail supplier.

b) Retail suppliers and their customers are to be responsible for all costs related to the provision of service by retail suppliers to their customers that would otherwise be the responsibility of NS Power and its customers.

c) Existing NSPSO market mechanisms and systems will be leveraged to the extent possible in the implementation, i.e. by leveraging existing OATT infrastructure and processes, where applicable.

d) The market administration solution will seek scalability in its implementation, to respond to market uptake.

NS Power has engaged the services of Robert Cary & Associates Inc. to assist the NS Power Renewable to Retail (RtR) project team in the design of the RtR market, including research of other jurisdictions' models, market design, development of an embedded cost recovery mechanism, design of distribution tariff as well as technical review of existing documentation (OATT, GIP, other Tariffs, market rules & procedures, and Standards of Conduct needed to facilitate the market).

Two Stakeholder Sessions have been held. The first session, held on June 17, 2014, included a review the legislative objectives of the Act by the NS Department of Energy staff, reviewed the draft Terms of Reference and described the overall development process. Comments were received from two Stakeholders (Cape Breton Explorations and Port Hawkesbury Paper) following the June session.

A second session held on October 9, 2014 focused primarily on market design topics. At the session, consultant Rob Cary presented the Renewable to Retail Project Market

Design White Paper (White Paper) which he authored for NS Power. Embedded cost recovery and distribution access tariff topics were presented by NS Power.

Within the body of the White Paper and throughout the presentation by Rob Cary, feedback from stakeholders across a number of fundamental topics was requested and encouraged. The feedback received is summarized and addressed in this report. If NS Power has inadvertently mischaracterized any stakeholder comments in the following, it asks stakeholders to please assist in clarifying.

Eight stakeholders provided written feedback after the October session[2].

- Cape Breton Explorations
- George LeBlanc Consulting
- Minas Energy
- Natural Forces Wind
- Nova Scotia Department of Energy
- Port Hawkesbury Paper
- Scotian WindFields Inc.
- Small Business Advocate

This Strawman document seeks to provide insight to Stakeholders' feedback received and provide NS Power's positions and perspectives on the issues and topics raised. The document supports a collaborative process to facilitate the development of consensus among the Company and stakeholders on these fundamental market design topics. The document is structured to align with the sections of the White Paper.

NS Power intends to present a summary of this Strawman report at the next stakeholder session scheduled for December 15, 2014.

[2] These documents can be found at http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/regulatory-initiatives/renewable-to-retail.aspx

2.0 POLICY OBJECTIVES

2.1 Success Measures

While not specifically addressed in the White Paper, comments were received from stakeholders suggesting success measures for the RtR market opening.

- Port Hawkesbury Paper stated that the creation of a functioning market in which new renewable projects can be financed and constructed is a critical measure of success. They commented that if the market structures do not provide the necessary flexibility and levels of certainty that are required for the development of new projects and for sale of renewable electricity to purchasers, the process will have failed to achieve its intended goal.

- Minas Energy proposes that the process needs to appreciate the challenges associated with developing projects that could offer competitive supply. They state there is no point developing a market model that will not enable project financing for competitive supply.

- George LeBlanc Consulting advised that the overall intent of the RTR initiative is to provide a competitive alternative to the present provincial power supply monopoly, increase the provincial renewable energy power production capacity, and ultimately lower or minimize power cost increases.

- Natural Forces Wind suggests consideration of market uptake objectives (i.e. a specified percentage of the market was to be contracted with new market entrants by a certain date), and proposes that such targets give prospective market entrants the confidence that the policy objective was clear and that a market would exist prior to entry. Natural Forces adds that another potential benefit of establishing a target market size is that doing so will help provide a better understanding of the costs that must be made up to the customers who remain with NS Power.

- The Small Business Advocate suggests that if the process results in increased development of renewable energy resources and does not create any cost subsidizations, it is a success. The SBA also holds that if the RtR transaction process is set without subsidization and little to no additional renewable energy is developed, then the legislation and its implementation is also a success.

NS Power Response and Recommendations:

NS Power's success measures are derived from the directives of the Act and the Regulations, and supported by the criteria established in the Terms of Reference for this initiative. The Act provides the fundamental success measures that: 1) customers of Nova Scotia Power and persons who are independent power producers or hold feed-in tariff approvals are not to be negatively affected if some retail customers choose to purchase renewable low-impact electricity from a retail supplier and 2) that retail suppliers and their customers are to be responsible for all costs related to the provision of service by retail suppliers to their customers. The Terms of Reference guide a process to support the obligations established by the Government of Nova Scotia in the Act. Neither the Act nor the Terms of Reference suggest that success of the process demands a degree of uptake in the market or a requirement to ensure project finance-ability. While not seeking to diminish the validity of the success measures related to renewable energy project development, NS Power considers them to beyond the scope of its role as stated in the legislation: "…Nova Scotia Power Incorporated shall develop in consultation with stakeholders, and file with the Board for approval, any tariffs, procedures and standards of conduct and any amendments to existing tariffs, procedures and standards of conduct that are necessary to facilitate the purchase of renewable low-impact electricity…"[3]

[3] 3G (1) of the Electricity Reform Act (2013)

3.0 MARKET DESIGN OPTIONS

3.1 Criteria for option design and selection

The White Paper proposed market design objectives to facilitate evaluation of options and confirmed the principles and criteria established to meet the legislative requirements. These were summarized as:

- NS Power retains its obligation to serve all customers as a default supplier,[4] and
- the institution of a Renewable to Retail ("RtR") market must not adversely affect any other wholesale or retail customers or any suppliers to NS Power.[5]

In addition it confirmed that the Terms of Reference set out as criteria:

- scalability (and associated capability of response to uptake); and
- the solution will leverage to the extent possible the existing NSPSO market mechanisms and systems.

The White Paper suggested that these criteria are best achieved by a design that provides simple implementation, predictable outcomes, and minimum regulatory or administrative burden. Stakeholders were invited to comment on the criteria and to offer any proposed additions.

Comments were received for three stakeholders in this area:

The NS Department of Energy (NSDOE) provided several comments related to market design and selection.

[4] Electricity Act 2004, as amended by the Electricity Reform Act 2013, section 3C (2)
[5] Electricity Act 2004, as amended by the Electricity Reform Act 2013, section 3G (2)

(1) NSDOE commented that transparency and openness of tariff structure and market model be considered a guiding principle for the development of the RtR market.

(2) In terms of scalability, NSDOE suggested that the level of effort in implementing the market design should be considered in the context of the expected size of the prospective market. In addition, they suggest that in order to support innovation and competition, the market model should possess flexibility to enable participation by future, technologically evolved market entrants possessing cost and supply structures which differ from current state without excessive regulatory burden.

(3) NSDOE reiterated that Subsection 3G(2) of the Electricity Act requires that all costs for the market opening be borne by retail suppliers and their customers, and emphasized that there should be no material difference in the costs to be recovered from the RtR market participants between the market model options being considered, and that option selection should be based on other factors such as transparency, flexibility and regulatory burden.

In addition, the following comments were received:

(4) The Small Business Advocate believes any of the designs presented can be implemented without creating subsidization of the RtR customers by the other NS Power customers.

(5) However, the Small Business Advocate does not believe that simplicity of implementation, simple and readily comprehensible solutions, predictability of outcomes, and minimum practical regulatory or administrative burden are major criteria in designing the market and that focusing on them could potentially introduce subsidization.

(6) Natural Forces Wind indicated that they are struggling to provide meaningful feedback in the absence of examples estimating the level of charges one would expect for the various elements based on other jurisdictions.

NS Power response and recommendations:

(1,5) NS Power agrees that transparency and openness are important principles for market design and will strive to achieve these in establishing a market solution. NS Power considers that simplicity of implementation, simple and readily comprehensible solutions, predictability of outcomes, and minimum practical regulatory or administrative burden are also important outcome measures for the solution, to be achieved while holding to the cost transfer principles of the Act.

(2) NS Power considers the scalability criteria in the Terms of Reference as applicable to the scenario described in NSDOE's comment regarding flexibility for future market participants.

(3,4,6) NS Power agrees that the no-harm principle (i.e. all costs for the market opening are to be borne by retail suppliers and their customers) will be critical to establishing the preferred market design. Also, we concur that any of the four options could be implemented without material cost transfer between the RtR market participant and NS Powers customers. However, NS Power recognizes that it may be necessary to demonstrate to stakeholders that there would be no material difference in the costs recovered under the different market model options.

3.2 Disaggregated tariff option

Comments were received from three stakeholders:

1. The Small Business Advocate favors the disaggregated tariff option and suggests it be the focus of implementation. The SBA says the disaggregated tariff option provides the greatest guard against cross subsidization and is simpler for the RtR customer as the majority of the transactions would lie with the Licensed Retail Supplier.

2. Natural Forces Wind considers the disaggregated tariff option to be the only market design that will fulfill the objective of an open and transparent market to foster competition and states that the increased transparency of separate charging and annual review by the UARB would provide increased confidence for new entrants. They also state that the disaggregated tariff option would make most sense in terms of scalability (numerous generators).

3. Scotian WindFields Inc. agrees with the disaggregated tariff option, and suggests that it be modified such that the RtR customer would make a single payment, made to the Licensed Retail Supplier.

3.3 Integrated RtR delivery service tariff

Comments were received from three stakeholders:

1. The Small Business Advocate states that while the integrated tariff option is acceptable, it is not preferred due to complex transactions for the RtR customer and the tariff being less real-time is prone to create subsidization.

2. Natural Forces Wind is opposed to a market design that sets the majority of a generator's revenue on avoided cost, and consequently believes that the integrated tariff option and the financial option will not work as the generator revenue stream is based mainly on avoided cost.

3. Minas Energy suggests that a compromise between complexity and utility control lies in the integrated (and hybrid) option.

3.4 Hybrid option

Comments were received from three stakeholders:

1. Natural Forces Wind sees merit to the hybrid option but the increased transparency of separate charging and annual review by the UARB as under a disaggregated tariff model would provide increased confidence for new entrants.

2. The Small Business Advocate expects some compromising of principles during the implementation process is likely given all the moving parts.

3. Minas Energy suggests compromise between complexity and utility control lies either in the hybrid (and integrated) option.

3.5 Financial market option

Comments were received from three stakeholders:

1. Minas Energy does not support the financial option.

2. Natural Forces Wind states that the financial option inhibits competition as the supplier will by default always be more expensive than NS Power (assuming that the RtR adder is above zero). Also, Natural Forces Wind does not believe that the financial option will work as the generator revenue stream is based mainly on avoided cost.

3. The Small Business Advocate would not oppose this option, stating that its simplicity is interesting. However, the SBA believes it is less likely to be the market maker for RtR sales.

4.0 COMPARISONS AND RELATIVE BENEFITS

4.1 Licensing differences

1. Minas Energy states that an LRS should obtain and maintain a license, which is the only qualification to participate in the market (subject to adhering to the GIP).

NS Power Response:

1. NS Power believes that the licensing requirements should not have a significant impact on the relative merits of different market design options.

2. Licensing terms and conditions will be determined by the NS Utility and Review Board. Market participation will be addressed during review of the Market Rules and Procedures, the OATT and the GIP.

4.2 Conclusions regarding option selection

Please refer to Stakeholder comments provided for each market design option in Sections 3.1 to 3.5.

NS Power Response & Recommendation:

In the White Paper, it is acknowledged that different market participants will have different and at times conflicting objectives and views on the development and/or implementation of the RtR market mechanisms and associates tariffs.

The integrated RtR delivery service tariff option has the advantage that it builds on existing market mechanisms and tariff structures to the extent that its avoided cost approach underlies several of NS Power's existing tariffs. Consequently, with the integrated RtR delivery service option, any contention is likely to be focused into a single "avoided cost" determination. Concern with the integrated delivery tariff's reliance on NS Power's avoided costs was highlighted by one stakeholder. NS Power suggests that work be undertaken to establish the methodology to determine the avoided costs. NS Power notes that work has been completed on avoided costs in the recent IRP process and that this could provide a useful starting point for the RtR avoided cost determination.

The disaggregated tariff option has the advantage of more discrete transactions through the RtR supply chain. However, due to the number of elements involved, this may bring forth a more extensive regulatory process to set provisions and rates for distribution service, backup, top-up and spill, as well as embedded cost recovery, and rates for surplus energy. The discussion will be much more granular, with focus on different aspects at different times. The broadest stakeholder support was received for the disaggregated tariff option.

The financial market option is unlike the other physical supply options, and while it shares with other proposals the challenge to establish NS Power's avoided costs, offers simplicity from an implementation and administration perspective. The stakeholder feedback received regarding option selection indicates there was minimal support expressed for the financial option, and NS Power suggests that further efforts to develop this model should not be undertaken at this time.

5.0 METERING AND SETTLEMENT

5.1 Meter ownership, meter reading and metering calculations

1. Scotian WindFields Inc. would like the Licensed Retail Supplier to be permitted to own independent metering, communication and other service infrastructure equipment to allow for bundling of packages and services for RtR customers.

2. The Small Business Advocate states that NS Power should remain the provider of metering, billing and customer service.

NS Power Position and Recommendation:

It is NS Power's view that retail customer metering should remain the responsibility of NS Power. This approach supports the ongoing NS Power service delivery relationship with the retail customer for service, trouble and outage response, and as the asset owner and maintainer of the physical electricity delivery assets. Existing metering quality and maintenance programs, inventories, meter reading and information capabilities can be leveraged for an overall lower cost for RtR consumers.

Metering reading data and information would be shared with the load customer and the LRS. Issues with coordination of meter changes for customer transfers can be minimized and would be accomplished on a more effective and timely basis as the meter would not have to be changed for a customer transfer to or from RtR service.

Customer class metering requirements would remain unchanged.

5.2 Transfers

1. Natural Forces Wind raised the question of whether customers who leave NS Power and subsequently transfer back to NS Power service would have their exit fee refunded.

NS Power Position and Recommendation:

NS Power defers comment on the question of transfers and refund of exit fees and suggests it be brought forward to the impending embedded cost recovery discussions.

5.3 Collection and settlement cash flow (including Billing)

1. Natural Forces Wind states that the billing should be made by the Licensed Retail Supplier. (Supplier Consolidated)

2. Scotian WindFields Inc. supports a supplier consolidated model for Collection and Settlement Cash flow and that a single electricity bill (from the Licensed Retail Supplier) is necessary to maintain simplicity and comprehensibility for potential RtR customers.

3. George LeBlanc Consulting states that there should be only one bill and it should be clear what remuneration is being paid to the RtR generator and NS Power.

4. The Small Business Advocate states that NS Power should remain the provider of metering, billing and customer service, and that the LRS may also bill and have customer service for their services and electricity.

NS Power Position and Recommendation:

The White Paper suggested three theoretical configurations for collection and settlement cash flows:

(1) Supplier Consolidated: the LRS would invoice and collect from RtR customers the NS Power delivery charges and RtR electricity charges.

(2) Split collection: NS Power would invoice and collect the NS Power delivery charge; the LRS would invoice and collect the RtR electricity charge.

(3) NS Power Consolidated in which NS Power would collect from RtR customers both the NS Power delivery charge and the RtR electricity charge.

NS Power believes that two of the three possible arrangements are potentially viable in Nova Scotia but considers the Supplier Consolidated billing approach to be problematic due to the fact that the LRS would have to bear all the customer credit risk and NS Power would likely have the right to net outstanding amounts against payments owed for RtR electricity injected by the generator. In addition, the LRS would need to have an approved RtR late payment mitigation processes, and absent that, any obligation on NS Power to take back an already defaulting load customer could be unreasonably onerous.

In other markets with retail competition (Alberta, Ontario) the incumbent utility is responsible for consolidating the T&D delivery charges as well as the competitive supplier's charges and provide the consolidated bill to the customer talking competitive service.

NS Power recommends the NS Power Consolidated approach.

6.0 AVOIDED COSTS AND ECR

Several comments were received related to the determination of avoided costs and embedded cost recovery. It is recognized that additional discussion and subsequent effort will be required to establish the Avoided Cost and Embedded Cost recovery approaches and rates for use in the RtR market. NS Power recommends that the following comments related to Avoided Costs and ECR be carried forward to be considered during that process. The comments are listed here for completeness.

6.1 Monthly, seasonal or annual rates

1. The Small Business Advocate favours avoided costs that are as close to a real time basis as possible and believes that use of a single annual avoided energy cost number will create subsidization.

2. Scotian WindFields Inc. suggests that an hourly in-advance model should be developed for calculation of avoided costs as well as top up and spill rates. They recommend this be done using averages from previous years to avoid the need to be calculated dynamically after the fact.

3. Natural Forces Wind states that settlement should be calculated on an annual basis with surplus energy and top-up energy being provided at avoided cost.

4. Scotian WindFields Inc. states that seasonal capacity requirements should be developed by NS Power and seasonal contributions for each type of renewable generation be agreed to for their contribution to this requirement.

6.2 Avoided energy costs

1. The Small Business Advocate recommends against use of generic estimates of production from renewable energy generation involved in the RtR transaction.

2. The Small Business Advocate recommends not using avoided costs created for other purposes, such as interruptible service tariffs.

3. The Small Business Advocate suggests that the process must estimate avoided costs as accurately as possible for each specific renewable energy generation facility.

6.3 Avoided capacity costs

1. Natural Forces Wind questions the merits of an avoided capacity calculation when there is limited requirement for new capacity on the system for some years to come.

2. The Small Business Advocate states that front-end loading of avoided capacity costs into the avoided costs used to develop RtR tariff pricing will create subsidization.

3. Minas Energy has deferred its comments on avoided costs.

6.4 Non-avoided costs and Embedded Cost Recovery

1. The Small Business Advocate supports placing embedded cost recovery as a priority to address.

2. The Small Business Advocate states that customers who partially or fully leave the generation service of NS Power are still obligated to pay a pro rata amount of recovery of any deferred costs that were incurred while that customer was a full NS Power customer.

3. The Small Business Advocate states that in order to avoid subsidization, the FERC-based lost revenue approach can be used.

4. Natural Forces Wind believes that exit fees would be an impediment to participation of retail customers in a new market.

5. Natural Forces Wind questions how new customers or a new market entrant that did not have a previous contract with NS Power will be treated relative to exit fees.

6. Natural Forces Wind questions how partial loads would be treated in respect to exit fees.

7. Natural Forces Wind questions how costs won't increase for existing customers if NS Power still plans capacity for customers who have entered the Renewables to Retail program.

8. Natural Forces Wind states that there should be no exit fees, as customers leaving NS Power happen currently regardless of the RtR program.

9. Scotian WindFields Inc. suggests NS Power should place ECR costs into three different categories: i) those required for the provision of service to RtR customers, ii) those required for the "obligation to serve" the RtR customer if they return to NS Power, iii) those not associated with the RtR program in any way.

10. George LeBlanc Consulting challenges the overall concept of ECR with respect to other efficiency initiatives which are being supported by the Government of Nova Scotia, e.g. LED lighting, increase insulation, switch to lower cost heating alternatives.

11. Minas Energy has deferred its comments on stranded costs, but expressed the risk that the current process will ultimately lead to an argument before the regulator on the issue of avoided and stranded costs.

6.5 Surplus energy rates

1. Please refer to Section 6.1 (3).

7.0 CONNECTION, NETWORK UPGRADE AND OPERATIONSL INTEGRATION

7.1 Generator location considerations

1. Cape Breton Exploration requests to add the option of an IPP delivering renewable energy to a consumer, without being connected to NS Power's system. They indicate that they would not support any presentation to the UARB that does not include this option.

NS Power Response & Recommendation:

NS Power assumes that the load customer remains connected to the NS Power system under this scenario. If this is the case, the IPP generator is electrically interconnected to the NS Power system and would be accommodated under the GIP.

7.2 Network upgrade costs

1. Given the principle in the legislation that no other generator can be harmed, Minas Energy asks whether the market can be designed to provide curtailment certainty to an existing project that was unwilling to pay for the benefits of Network Resource Interconnection Service. Minas Energy suggests that the option to pay for and upgrade to Network Resource Interconnection Service could be made available to existing facilities connected with Energy Resource Interconnection Service.

NS Power Response & Recommendation:

The option for an ERIS generation facility to upgrade to an NRIS facility is available under the GIP.

8.0 OTHER DESIGN ISSUES

8.1 Distribution tariff development

1. The Small Business Advocate supports the implementation of the Distribution Service Tariff as presented at the October 9th session.

2. Natural Forces Wind states that OATT payment and distribution service payments should be independently approved annually by the UARB.

3. Natural Forces Wind states that OATT payment and distribution service payments should be benchmarked against other comparable jurisdictions.

NS Power Response & Recommendation:

These comments will be taken into account during development of the Distribution Access Tariff.

8.2 Customer Service

These comments relate to the ongoing provision of customer service to RtR customers after they depart from NS Power.

1. Scotian WindFields proposes that in the event of service interruption, service outages or interconnection problems, the customer will still be advised to contact Nova Scotia Power Inc. directly, as the owners and operators of the transmission and distribution infrastructure.

2. Scotian WindFields proposes that NS Power will still maintain ownership and control of interconnection, transmission and distribution infrastructure.

3. The Small Business Advocate recommends that NS Power will continue to maintain the distribution service, including outage restoration, and NS Power will be the administrator of the RtR market and provide OATT services.

NS Power Response & Recommendation:

NS Power is in agreement with the stakeholder comments.

8.3 Partial Service

1. Port Hawkesbury Paper commented that it is important that retail customers have the opportunity to receive competitive service from renewable electricity suppliers for only a portion of their load requirements.

NS Power Response & Recommendation:

Provision of partial service to the RtR market was not envisioned by the legislation. Inclusion of a partial service option that fulfills the no harm principles of the legislation would add significant complexity to the design and potentially result in an administratively complex and burdensome RtR solution, and could challenge the development and implementation timelines. The level of complexity is also dependent upon the market model utilized, and the type of retail service the RtR customer would take from NS Power as part of their partial service.

For these reasons, NS Power suggests partial service not be introduced as a design requirement for the RtR market.

Nova Scotia POWER
An Emera Company

DECEMBER 15, 2014

Stakeholder Session #3

Renewable to Retail Market Opening
Stakeholder Feedback Strawman

Feedback Received

- Eight stakeholders provided written feedback after the October session. Thank you.
- Comments were categorized into topic areas aligned with Market Design White Paper
- Reviewed for consensus.
- Strawman report was created to consolidate feedback received and offer NS Power's views.
- This presentation summarizes the report.
  - If NS Power inadvertently mischaracterized any stakeholder comments in the following, please assist in clarifying.

Nova Scotia POWER An Emera Company

Option Design and Selection

- No single option emerged as a frontrunner, minimal support for the Financial Option.
- Top-Down (Integrated) and Bottom-Up (Disaggregated) approaches remain.
- Key topics: Avoided Cost (Integrated) and Embedded Cost Recovery (Disaggregated)
- Recommendations:
  - Work be undertaken to establish the methodology to determine the avoided costs.
  - Work should continue on Embedded Cost Recovery.
  - Further efforts to develop the financial option should not be undertaken at this time.

Meter ownership, meter reading and metering calculations

- A range of views were expressed on meter ownership.
- Recommendation:
- Retail customer metering should remain the responsibility of NS Power.
  - Supports the ongoing NS Power service delivery relationship for service, trouble and outage response.
  - NS Power is the asset owner and maintainer of the physical electricity delivery assets.
  - Existing metering quality and maintenance programs, inventories, meter reading capabilities are utilized.
  - Meter reading data and information would be shared with the load customer and the LRS.
  - Minimizes coordination efforts for meter change outs when customers transfer to/from retail suppliers.
- To be addressed in the Distribution Service Tariff.

Collection and settlement cash flow (including Billing)

- Views differed on the topic of billing responsibility (Supplier vs. NS Power billing).
- One bill with separation of costs was preferred over two separate bills to the RtR customer.
- Recommendation:
  - NS Power Consolidated approach with the competitive supplier's electricity charges as well as NS Power's T&D delivery charges shown separately on the bill.
- To be addressed in the Distribution Service Tariff and/or the Market Rules.

Nova Scotia POWER An Emera Company

Customer Service

- Recommendation:
  - NS Power will provide ongoing customer service to RtR customers after they depart from NS Power in the event of service interruptions, outages or interconnection problems.
  - NS Power will maintain ownership and control of, transmission, distribution and interconnection infrastructure (consistent with GIP).

Nova Scotia POWER
An Emera Company

Partial Service

- Partial service for the RtR market was not envisioned by the legislation.
    - Adds significant complexity to the design.
    - Administratively more complex and burdensome RtR solution.
    - Challenges the development and implementation timelines.
- Recommendation:
    - Partial service not be introduced as a design requirement for the RtR market.

Nova Scotia POWER An Emera Company

Success Measures Identified for the RtR Process

- New renewable projects can be financed and constructed.
- Flexibility and certainty required for the development of new projects and for sale of renewable electricity to purchasers.
- Enable project financing for competitive supply.
- Provide a competitive alternative to the present monopoly.
- Increase the provincial renewable energy power production capacity.
- Lower or minimize power cost increases.
- Consider market uptake objectives.
- Increase development of renewable energy resources and do not create any cost subsidizations.
- **While it is important to be mindful of these objectives as we proceed through this process, NS Power's measure of success is development of a collaborative, transparent Renewable to Retail framework which complies with directives of the Act and the Terms of Reference criteria.**

Nova Scotia POWER An Emera Company

Nova Scotia Power
Renewable to Retail Project
ECR White Paper

Robert Cary & Associates Inc.

December, 2014

Structure of presentation

- Part 1: context (white paper sections 2.1 and 1)
  - *Embedded Cost Recovery*
  - *Principles of stranded assets*
  - *Concepts of stranded assets*
  - *The Nova Scotia context*
- Part 2: overview of other jurisdictions (white paper section 2)
  - *FERC / Ontario / Other Provinces / US jurisdictions*
- Part 3: what assets are stranded (white paper sections 3 & 4)
  - *Generation capacity (including Appendix A discussion)*
  - *Renewable energy cost premium*
  - *Other*
  - *Overview charts*
- Part 4: Options for ECR mechanisms (white paper section 5)
  - *Retail Access Adjustment*
  - *Exit Fee*
- Part 5: Consultation Questions (white paper section 6)

Embedded Cost Recovery (2014 10 09 presentation slide 23)

- The other side of the avoided cost coin

- Embedded cost recovery is necessary whenever the application of a particular tariff structure would otherwise omit recovery of costs that are not avoided
  - *Such costs cannot be transferred to other customers*
  - *Must be borne by RtR market participants*

- This is not an issue in the financial market option, or to the extent that tariffs are specifically based on avoided costs
  - *Embedded costs are by their nature not avoided*

ECR & principles of stranded assets

- FERC described the principle:
  - *"[i]f a former wholesale requirements customer or a former retail customer uses the new open access to reach a new supplier, the utility is entitled to seek recovery of legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer."*

- Applications:
  - *Full market restructuring*
  - *Wholesale and retail market customer exit:*
    - *as a consequence of open access*
    - *not as a result of normal customer changes*

Stranded asset concepts

- Specific assets that become completely redundant
  - *Possible but unlikely in the immediate context of Nova Scotia RtR*

- Assets / Capacity that becomes partly used, partly redundant
  - *Likely in the Nova Scotia RtR context*

- Assets which become financially devalued
  - *Typical in a full market restructuring*
  - *Another way to view the consequences of Nova Scotia RtR customer exit*
    - *the loss of revenue devalues the asset*

- Contract commitments result in assets or goods (eg purchased energy) that become redundant

- Debt and liabilities associated with above assets or commitments

Nova Scotia context

- IRP indicates no load growth over many years, and thus no need for new major investments
  - *This is significant because there is no alternative use for assets / capacity that are stranded by retail exit.*
  - *NS Power has indicated that the only variable investment in the province in response to changes in demand is in DSM.*
  - *To the extent that DSM goals are flexible, the ability to reduce DSM provides some scope for NS Power to mitigate stranding.*
    - *this depends in part on the available notice for customer return to NS Power service relative to the investment timeframe in DSM or other resources.*

- My assumption is that all RtR generation assets will be connected as NRIS resources, so that they can contribute to fulfilment of provincial adequacy requirements
  - *Capacity contribution as other resources of similar technology connected on a similar basis and with similar NSPSO call rights.*

Other jurisdictions

- Restructurings
  - *NE RTOs*
  - *California*

- Wholesale customer exit
  - *following FERC 888 pro-forma tariff*
    - *New Brunswick*
    - *Quebec*
    - *Saskatchewan*

- Retail customer exit
  - *Ontario*
    - *Wholesale & retail Debt Retirement Charge and*
    - *Global Adjustment*
      - *but not really a stranded asset issue*
      - *more like a system benefits charge includes capacity, conservation, renewables premium, etc*
  - *eg Pacific Power, Portland General Electric, & Public Service of New Hampshire*

What assets are stranded: basic capacity construct # 1

- RtR customers will expect the same reliability of supply as others
  - *Embedded within distribution zones, they are largely indistinguishable from other customers*
  - *NS Power has to supply this reliability*
    - *different from wholesale*

- Reliable supply requires
  - *Adequacy of overall system capacity*
    - *the overall system must be planned to have firm capability equal to the coincident peak demand plus a 20% reserve margin*
    - *each customer or customer class share of this total capacity requirement is that customer's coincident peak demand + 20%.*
    - *firm capability provided by a combination of self-supply by the RtR supply chain and NS Power backup service*
  - *Energy balancing (top-up and spill services, and unscheduled imbalance services)*
    - *to address differences between generation profile and load profile*

What assets are stranded: basic capacity construct # 2

- Appendix A examples; customer parameters (100% compliance obligation)

RtR customer parameters

Sum of non-coincident peak demands		50	MW	illustration input
Contribution to system coincident peak		40	MW	illustration input
Reserve margin required	20%	8	MW	NS Power reserve margin
Total adequacy obligation		48	MW	
Minimum coincident load		15	MW	illustration input
Average customer load factor		50%		illustration input
Total annual energy consumption		219,000	MWh	
Average T&D loss factor (% of delivery)		5%		illustration input
Total annual energy injection requirement		229,950	MWh	

What assets are stranded: basic capacity construct # 3

- Appendix A examples; wind generator

NRIS Wind generator example

Planned surplus generation	2%		illustration input
Target annual production	234,549	MWh	
Production factor	35%		NS Power typical
Installed capacity	76.5	MW	
Maximum spill	61.5	MW	= capacity - min load
Dependable capacity contribution	17%		IRP
Dependable capacity contribution	13.0	MW	= capacity x contribution %
Backup capacity obligation	35.0		= adeq oblig'n - dep cap'cty

What assets are stranded: capacity

- In this example

	wind	biomass
Overall capacity obligation	*48 MW*	*48 MW*
Self-supply firm capability	*13 MW*	*33.5 MW*
Backup capacity obligation	*35 MW*	*14.5 MW*
Potentially stranded NS Power capacity	*13 MW*	*33.5 MW*

- The Embedded Cost Recovery required in respect of this stranded capacity is the average charge that NS Power would have made for that capacity less any mitigation that NS Power can achieve
  - *That charge would have been embedded in the demand and / or energy rates charged to customers*
  - *Mitigation may take the form of:*
    - *avoided capacity cost (but limited opportunity except possibly DSM)*
    - *incremental export revenues for capacity (or the premium associated with firm energy)*

What assets are stranded: RES obligation premium

- Consider the illustration
  - *2020 RES obligation is 40% of 11,250 GWh of total planned load = 4,500 GWh*
  - *Appendix A illustration displaces 230 GWh of NS Power load*
  - *2020 RES obligation reduces to 40% of 11,020 GWh = 4,408 GWh*
  - *NS Power has fully committed to this energy, and cannot reduce its financial obligation to purchase (or service the capital and operating costs)*
  - *Procurement of 92 GWh of RES energy is thus stranded*
  - *The amount stranded is based on the premium paid by NS Power for this energy over the energy costs of other forms of energy, less any mitigation*

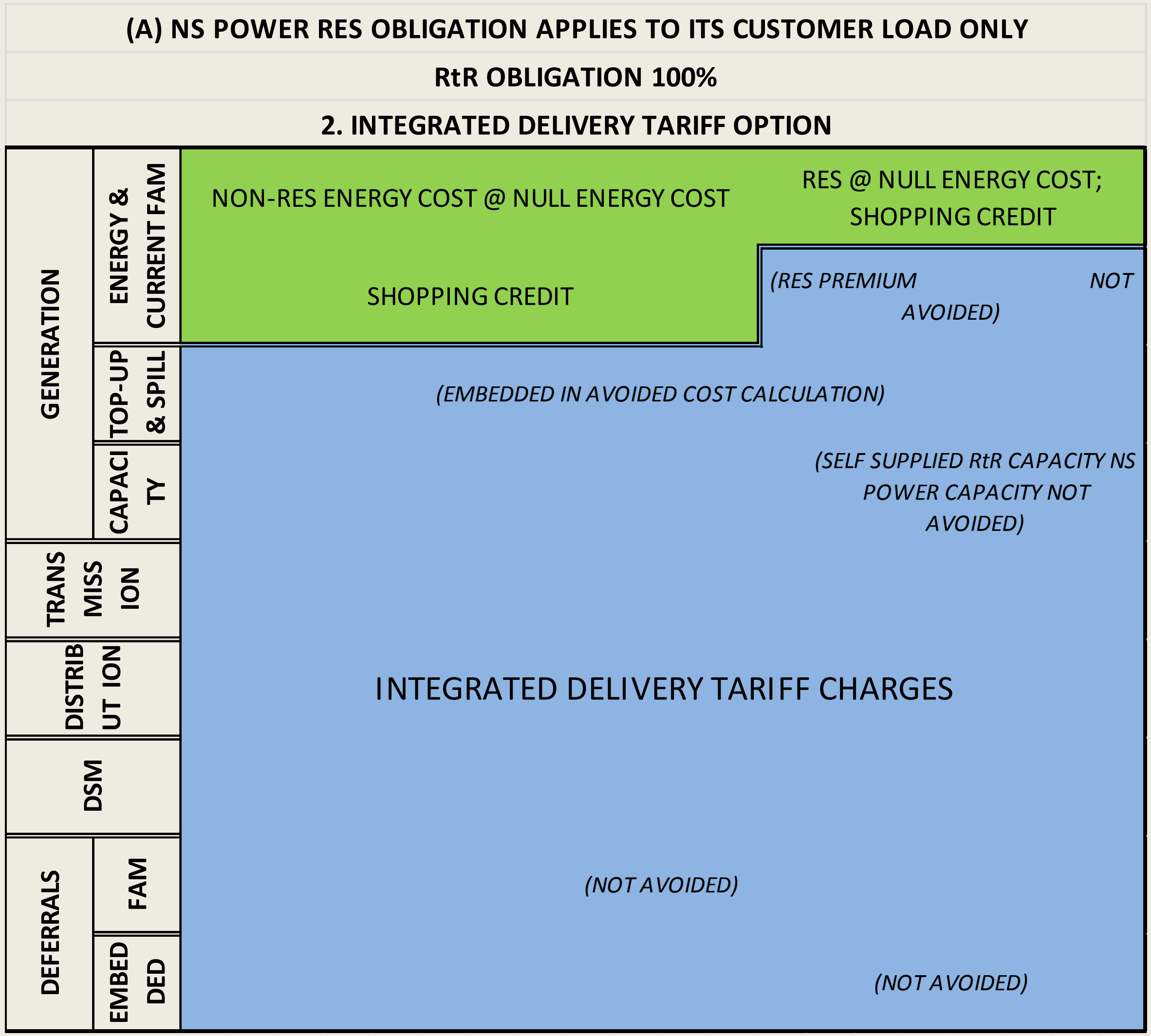
What assets are stranded: other *as proposed*

- Transmission
  - *None stranded: collected through tariff on RtR customer load*
- Distribution
  - *None stranded: collected through tariff on RtR customer load*
- DSM
  - *None stranded: ongoing service delivery with associated charge including to RtR customers*
- Actual and Deferred FAM balances
  - *ECR required: balances otherwise stranded*
- Other deferrals
  - *ECR only required if these recoveries are not embedded into distribution tariff*

What assets are stranded: summary - disaggregated

(A) NS POWER RES OBLIGATION APPLIES TO ITS CUSTOMER LOAD ONLY			
RtR OBLIGATION 100%			
1. DISAGGREGATED TARIFF OPTION			
GENERATION	**ENERGY & CURRENT FAM**	NON-RES ENERGY COST @ NULL ENERGY COST	RES @ NULL ENERGY COST; NOT CHARGED
		NOT CHARGED	RES PREMIUM ECR
	TOP-UP & SPILL	CHARGED OR CREDITED ON HOURLY BASIS	
	CAPACI TY	BACKUP TO MEET SYSTEM NEEDS CHARGED UNDER BACKUP TARIFF	SELF SUPPLIED RtR CAPACITY STRANDS NS POWER CAPACITY AND CAUSES ECR
TRANS MISS ION		OATT CHARGES	
DISTRIB UT ION		DISTRIBUTION TARIFF CHARGES	
DSM		CURRENT AND DEFERRED DSM CHARGES	
DEFERRALS	**FAM**	STRANDED FOR RECOVERY UNDER ECR	
	EMBED DED	CHARGED UNDER OATT OR DISTRIBUITION TARIFF	ANY ITEMS NOT CHARGED ARE STRANDED & BECOME ECR

What assets are stranded: summary - integrated



Options for ECR mechanisms

- Retail Access Adjustment
  - *A rate approved by the UARB for ongoing embedded cost recovery*
    - *based on existing customer charge determinants (peak demand, energy, monthly)*
    - *set to recover lost revenue after any mitigation reasonably available to NS Power, including on a deferred basis the outstanding FAM & deferral balances*
    - *likely the same for all RtR customers*
    - *or could add complexity with declining allocation over time to address expectation of increasing ability to mitigate*
  - *Challenge in dealing with uniform rate approach and one-off items like FAM balances*

- Exit Fee
  - *A rate approved by the UARB for lump sum embedded cost recovery*
    - *based on existing customer historic charge determinants (peak demand, energy)*
    - *set to recover actual outstanding deferral balances and present value after mitigation reasonably available to NS Power of ongoing stranded amounts*
  - *Challenge in dealing with customer re-entry and / or re-exit*

Choice of ECR mechanism: proposed considerations

- It is appropriate to consider:
  - *The approach should be transparent and fair; the overview and rate approval by the Board should provide assurance of this*
  - *The approach should be comprehensible and as predictable as possible*
  - *The approach should avoid undue administrative complexity*

- The approach may be further affected by:
  - *Settlement arrangements (are ECR charges settled by customers or by the LRS)*
  - *Technology issues and the relationship among for instance backup charges and ECR charges*
  - *Minimum commitment periods and notice periods for switching*
  - *Minimum notice periods for normal return to NS Power service, and conditions attached to shorter notice return*

- The approach may have an impact on the way that RtR supply is marketed.

Consultation questions

- Section 1.5 assumptions
  - *Target for surplus?*
  - *NRIS connection?*

- Section 5.1 types of ECR
  - *Any other ECR categories?*

- Section 5.2 generic ECR options
  - *Other ECR options?*

- Section 5.3 option selection
  - *5.3.1; other selection considerations?*
  - *5.3.2; reasonable design assumptions?*
  - *5.5.3; other considerations?*

DALHOUSIE UNIVERSITY
OFFICE OF SUSTAINABILITY

January 9, 2015

Nova Scotia Power Inc.
1223 Lower Water St.
Halifax, Nova Scotia
B3J 2W5

RE: December 15, 2014 - Renewable to Retail Technical Workshop

Thank you for the opportunity to comment on draft development documents for the Renewable to Retail Program. This program provides an opportunity for customers to meet carbon, community, and organizational values.

There are fees proposed to be collected as part of the program to recover money for existing power assets. It will be challenging for organizations to participate in this program if the renewable energy offerings become too costly due to additional fees especially if carbon pricing or carbon neutral legislation is not in place. In some US states, exit fees have been waived for renewable energy and CHP Projects (Source US EPA).

In Section 5.3.2 of Robert Cary's White Paper the notion of Partial Service is raised. For a large organization like Dalhousie it would be important for us to be able to access the program where one or two of our accounts may utilize a different renewable energy provider as opposed to requiring all of our power accounts be with one service provider.

We look forward to further developments of this initiative.

Sincerely,

Rochelle Owen

Digitally signed by Rochelle Owen
DN: cn=Rochelle Owen, o=Dalhousie University, ou=Office of Sustainability, email=rjowen@dal.ca, c=CA
Date: 2015.01.09 17:06:39 -04'00'

Rochelle Owen
Director Office of Sustainability
Dalhousie University
Central Services Building
5th Floor, 1236 Henry Street
P.O. Box 15000
Halifax, NS B3H 4R2
(902)-494-7448 (ph)
Email: rjowen@dal.ca

NOVA SCOTIA
Energy

Joseph Howe Building, 11th Floor
1690 Hollis Street
PO Box 2664
Halifax, Nova Scotia
Canada B3J 3P7

424-4575 T
424-3264 F
novascotia.ca

January 9th, 2015
Via EMAIL: Linda.Lefler@nspower.ca

Linda Lefler, P.Eng., Regulatory Project Manager
Nova Scotia Power Inc.
1223 Lower Water Street
Halifax, Nova Scotia
Canada B3J 2W5

Dear Ms. Lefler,

RE: M06214 Renewable to Retail technical conference, December 15th

After reading the "Embedded Cost Recovery" whitepaper by Rob Cary and attending the technical conference on December 15, 2014, the Department of Energy (herein referred to as "the Department") would like to offer the following comments:

1. While there remains a need for a continued and more fulsome discussion of avoided costs in order to define the remaining market models, the Department believes that many of the same issues must be discussed as were presented in the most recent session. Given that much of the same information will be used to define the market, the Department believes that the dis-aggregated model best preserves and presents the content of these discussions and that presenting and preserving the information is key to transparency and ensuring that the over-arching principles embedded in legislation are satisfied while creating new market opportunities for renewable energy retailers.

2. The Department notes that, while parties expressed a desire to keep options open in several areas, each of these options has the potential to increase the scope of work that must be performed before the deadline. While some openness and flexibility may be desirable, the Department proposes that each decision regarding options be considered for impact on schedule, and if a significant impact is expected then a decision on a single option must be made.

3. The Department is open to considering a market design that allows customers to divide their energy use in to parts and purchase different parts from different vendors, provided this option does not significantly increase the complexity of tariff design and is possibly limited to larger customers.

4. Finally, the Department would like to clarify that, the success or failure of the retail market opening will be judged by how it satisfies the over-arching principles embedded in legislation while creating new market opportunities for renewable to retail sales.

Respectfully,

Peter Craig, P.Eng.

MCINNES COOPER
LAWYERS | AVOCATS

James A. MacDuff
Direct +1 (902) 444 8619
james.macduff@mcinnescooper.com

Purdy's Wharf Tower II
1300-1969 Upper Water Street
PO Box 730
Halifax NS
Canada B3J 2V1
Tel +1 (902) 425 6500 | Fax +1 (902) 425 6350

Our File: 100384
January 9, 2015

Ms. Linda Lefler, P. Eng.
Regulatory Project Manager
Nova Scotia Power
P.O. Box 910
Halifax, NS B3J 2W5

Dear Ms. Lefler:

Re: Renewable to Retail Process – Feedback on October 9, 2014 Technical Conference

On December 5, 2014, Nova Scotia Power Inc. ("NS Power") circulated documents for discussion at the technical conference that was held with stakeholders on December 15, 2014. Please accept the following feedback on behalf of Port Hawkesbury Paper LP ("PHP") following the technical conference.

NS Power's Strawman Report (dated December 5, 2014) and Robert Cary's Embedded Cost Recovery White Paper (dated December 2, 2014) address a number of issues relating to the Renewable to Retail market. At this time, PHP would like to provide comments on the following three specific items: (1) Success Measures; (2) Determination of Avoided and Embedded Costs; and (3) Partial Service.

1. Success Measures

At page 8 of its Strawman Report, NS Power states that: "Neither the Act nor the Terms of Reference suggest that success of the process demands a degree of uptake in the market or a requirement to ensure project finance-ability."

The Objective of the Terms of Reference is: "To develop and implement a framework in Nova Scotia for competitive renewable electricity supply to retail customers, as directed by the Electricity Reform Act (2013), in alignment with the Province's timelines." As stated in its earlier comments, from PHP's perspective, the development of a framework for competitive renewable electricity supply will not serve its purpose unless it results in the creation of a truly functioning market.

While it is clear that the ultimate regime will need to be consistent with the specific directives and requirements set out in the Act, this process should remain focused on ensuring that the market structures that are implemented provide as much flexibility and levels of certainty as possible for renewable electricity suppliers to pursue the potential development of new projects and to market their product to purchasers of electricity. In circumstances where discretion may exist in the selection of various alternatives, such discretion should be exercised in favour of the options that are most likely to result in the creation of a functioning market.

2. Determination of Avoided and Embedded Costs

At page 16 of its Strawman Report, NS Power states: "NS Power suggests that work be undertaken to establish the methodology to determine the avoided costs. NS Power notes that work has been completed on avoided costs in the recent IRP process and that this could provide a useful starting point for the RtR avoided cost determination."

PHP agrees that work should be undertaken to examine the potential methodologies that could be used to determine avoided costs as part of the Renewable to Retail framework. As part of this exercise, PHP believes it would be very useful to all participants if NS Power could provide high-level estimates of the expected annual avoided costs based on the current assumptions from the recent Integrated Resource Plan ("IRP") process, broken down to the extent possible and with an explanation as to how those calculations fit within the overall framework and model designs under discussion. This would provide parties with important information on the potential magnitude of the avoided costs, as well as the basis for understanding the key inputs that must be determined in order to calculate such costs. Further refinement and determination of the appropriate avoided cost methodology will only be possible once this information has been circulated and reviewed in detail.

In terms of embedded cost recovery, PHP expects that this concept will be subject to more detailed examination and discussion as this process unfolds. At this time, PHP offers the following preliminary comments on some of the points raised in Robert Cary's White Paper:

- At page 13, the White Paper states: "Any permanent migration that NS Power might seek to undertake is limited by NS Power's obligation to recognise its obligation to serve any RtR customers who choose to return to NS Power service, and NS Power's obligation to include such eventuality in its planning."

  As mentioned at the technical conference, PHP is not clear as to why NS Power would be required to maintain any obligation to plan to serve a customer once that customer chooses to take service from a renewable retail supplier, particularly if that change in service is to be provided under a long-term contract. If this were the case, then it could require a retail customer to pay twice for the capacity required to serve its electricity needs. While NS Power retains a general requirement to serve under the *Public Utilities Act*, and cannot refuse service to a customer solely on the basis that it is also taking renewable supply (see further discussion on this point below in the context of Partial Service), PHP is not aware of any requirement in the legislative framework that NS Power must continue to plan to serve retail customers who voluntarily leave its system to support the construction of new renewable supply in the Province. Forcing potential retail customers to pay NS Power to retain (and potentially build) capacity for them even after they have chosen to leave the system does not seem to make sense in the context of the type of market opening contemplated by the Act.

- At page 15, the White Paper raises the possibility that Renewable Energy Standards ("RES") compliance premium costs are appropriately the subject of embedded cost recovery. For the reasons stated at the technical conference, PHP does not believe that RES energy costs should be the subject of embedded cost recovery. If this concept is accepted, then retail customers who choose to purchase 100% of their electricity from renewable retail suppliers other than NS Power would then also be required to pay an additional premium on account of the amount of renewable electricity used by others in the Province. This requirement could lead to contested and complicated calculations as to the extent of any premium and the specific amount of RES energy that NS Power had specifically obtained for that particular customer. More importantly, however, it is not clear whether such costs should be considered stranded, given that the retail customers will be contributing to the construction of new, 100% renewable generation if they choose to leave the system. Such new renewable energy would further increase the overall amount of renewable electricity in Nova Scotia consistent with the Province's policy objectives, and also provide benefits to NS Power's customers in terms of compliance with environmental emission restrictions.

- At page 16, the White Paper states that retail customers that are eligible for centrally funded Demand-Side Management ("DSM") services are properly subject to a charge for those services, even if they are no longer customers of NS Power. Since the primary regulatory justification for DSM spending in Nova Scotia is to reduce the capacity and energy requirements on NS Power's system, it would seem appropriate that retail customers who contribute substantially to this effort - by removing all (or a portion of) their load from that system - should not be additionally charged for programs designed to further reduce NS Power's load. The basis for regulatory approval of any DSM spending that would be applicable to retail customers who are no longer customers of NS Power is different than for NS Power customers. It follows that differential treatment with respect to the cost obligations for such customers is appropriate, particularly in recognition of the fact that these customers have already taken action to reduce their demand on NS Power's system.

In considering the issues related to items such as capacity obligations, RES compliance, and DSM spending, it is worth noting the value that the IRP places on reductions in demand and energy on NS Power's system. The participants in the Renewable to Retail framework accomplish virtually the same goal of reducing load on NS Power's system if they choose to take service from an alternate supplier. To the extent that there are any benefits associated with this load leaving the system, this needs to be properly considered alongside any potential stranded costs that have been identified to ensure that the framework under development is consistent with the requirements and the intent of the Act.

3. Partial Service

At page 26 of its Strawman Report, NS Power states that: "Provision of partial service to the RtR market was not envisioned by the legislation. Inclusion of a partial service option that fulfills the no harm principles of the legislation would add significant complexity to the design and potentially result in an administratively complex and burdensome RtR solution, and could challenge the development and implementation timelines."

PHP disagrees that the provision of partial service was not envisioned by the legislation. Section 3C(1)(b) of the Act provides a retail customer with the right to purchase renewable low-impact electricity generated within the Province from a retail supplier. There is no provision requiring that <u>all</u> of the retail customer's electricity be purchased in that fashion.

In fact, Section 3C(2) of the Act goes on to state that: "Nova Scotia Power Incorporated shall not refuse to provide service to a retail customer on the basis that the customer purchases renewable low-impact electricity from a retail supplier." This Section of the Act clearly contemplates the situation where customers would be permitted to purchase a portion of their electricity from a retail supplier, and specifically requires that NS Power not refuse to provide service for the remainder of that customer's electricity needs in such a circumstance.

At the December 15, 2014 technical conference, many participants (including NS Power) appeared to be supportive of allowing partial service for customers over a certain minimum load threshold. This could well be an appropriate resolution to this issue.

PHP appreciates the opportunity to continue its participation in the ongoing collaborative development of a successful renewable to retail market in Nova Scotia.

Yours truly,

James MacDuff

cc: Interested Parties

(19098861)

Scotian WindFields
Community Owned. Naturally.

January 9th, 2015

Nova Scotia Power Inc.
1223 Lower Water St.
Halifax, Nova Scotia
B3J 2W5

RE: M0614 – Comments Regarding Dec 15, 2014 Technical Conference

Scotian WindFields Inc. welcomes the opportunity to participate in the RtR Market Opening process and submits the below comments and suggestions regarding the December 15th, 2014 Technical Conference and supporting ECR White Paper and documentation, as well as supporting comments regarding the RtR overall structure and framework.

- Success Measures of the RtR program
- Supplier Consolidated Billing Model
- Extent of ECR Recovery and Avoided Costs
- Suggested RtR Framework Option
- Partial Service Options
- Response to NSPI Strawman Report

Scotian WindFields Inc. also would like to request that input and clarification from the Nova Scotia Department of Energy be provided regarding the extent of Embedded Cost Recovery. While it is clear that costs are not to be borne by existing customers and IPPs, clarity could be provided for which costs are to be borne by Licensed Retail Suppliers and which are to be borne by Nova Scotia Power Inc.

Should you require any clarification or further details on and of the points included in this response, please do not hesitate to contact Scotian WindFields Inc. directly.

Thank you for your consideration of these comments and we look forward to further discussion and analysis.

Sincerely,

Daniel Roscoe, P.Eng.
Chief Operating Officer
Scotian WindFields Inc.

Scotian WindFields
Community Owned. Naturally.

1) Success Measures of Renewable to Retail Program

Scotian WindFields Inc. feels that measurable uptake of the RtR program, and a viable market opportunity for renewable energy suppliers in Nova Scotia be considered as success measures for this program.

Scotian WindFields Inc. feels that legislation would not have been attempted if there was an expectation of no, or very little, participation. It is clear by stakeholder consultation and by comments made by the Nova Scotia Department of Energy that the success of this program is in its ability to create a viable market opportunity for renewable energy sales in Nova Scotia from Licensed Retail Suppliers.

With this in mind, Scotian WindFields Inc. feels that the financing capabilities of renewable projects and overall market uptake are key items to consider within the mandate RtR framework creation.

2) Supplier Consolidated Billing/Pricing model.

Scotian WindFields Inc. would like reaffirm our support for a Supplier Consolidated model for Collection and Settlement Cash flow, as described in section 4.5 of the October White Paper. Scotian WindFields Inc. feels strongly that in order to maintain simplicity and comprehensibility of the RtR system - as outlined in the Criteria of the White Paper – a single electricity bill, from the LRS, is necessary.

Scotian WindFields Inc. feels that the Supplier Consolidated billing option maintains a competitive market as it does not create a situation where commercially sensitive information is shared with or between Suppliers; however under the NSPI Consolidated model, commercially sensitive information owned by each LRS will need to be shared and administered with Nova Scotia Power Inc. through billing systems and process.

This allows for the various charges, tariffs and payments to be handled between the LRS and Nova Scotia Power Inc. These charges can be disclosed to the RtR customer, as a billing item or otherwise, but will not be the responsibility of the customer to coordinate, negotiate or pay directly.

Scotian WindFields Inc. is aware of potential financial risk and security issues regarding customer management, payment schedules and customer credit. We feel that these issues will be an understood portion of LRS licensing and operation to consider these factors.

Furthermore, it is the interpretation of Scotian Windfields Inc. that strong support of Supplier Consolidated billing was shown during the December 15th technical conference.

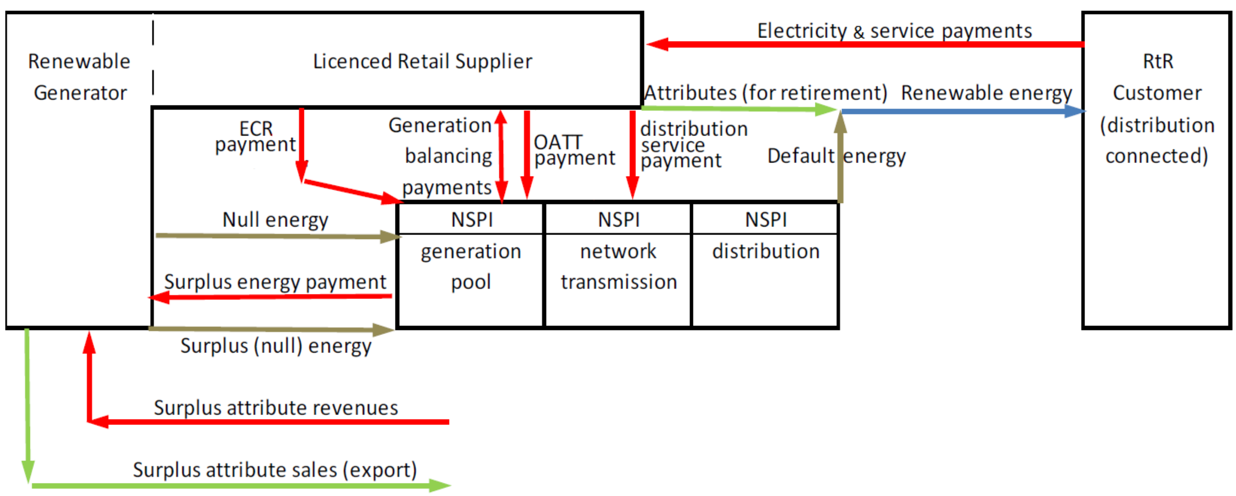
108F Trider Cres, Dartmouth, NS B3B-1R6|
info@scotianwindfields.ca | www.scotianwindfields.ca

Scotian WindFields
Community Owned. Naturally.

3) Suggested RtR Framework Option

To supplement the information given in the remaining portions of this submission, Scotian WindFields Inc. would like to reiterate support for the below framework as an Option for consideration of the RtR market framework.

This model is based on the Option outlined in section 2.2 of the White Paper – Disaggregated Tariff Option. Scotian WindFields Inc. agrees with this approach, and would like to suggest further simplifying the experience for the RtR customer by being responsible for a single payment, made to the LRS. All payments are tariffs, as well as the details of compliance, energy metering and interconnection will all be considered and negotiated between Nova Scotia Power Inc., the LRS and the Renewable Generator.



Scotian WindFields
Community Owned. Naturally.

4) Embedded Cost Recovery

Scotian WindFields Inc. recognizes the need for an analysis, discussion and resulting tariff regarding Embedded Cost Recovery. In general, Scotian WindFields Inc. supports the need to investigate ECR considerations and payments as they pertain to legitimate expenses, however does not support compensation for Nova Scotia Power return on equity or costs associated with increasing the efficiency of the electrical system.

Regarding the **Fuel Adjustment Mechanism**, Scotian WindFields Inc. sees the need for a quantifying framework for these costs, and requests further investigation. It is considered that uptake in the RtR program may create a need to limit total exposure and time associated with FAM balances, in that less fuel may need to be considered after an established RtR market.

Scotian WindFields Inc. feels that any level of **RES** that is carried by the Nova Scotia Power Inc. generation fleet that is over the currently-legislated 40% is ineligible for ECR consideration. The RES standards were implemented for a number of reasons, including emissions hard caps and overall RES uptake. To this end, and as current and future RES do not inherently come at a cost premium, we feel that considering ECR in this case is not necessary.

Scotian WindFields Inc. feels that all **network and grid costs** can be considered by the updated OATT and Distribution Tariff costs already to be considered as part of the RtR program. In the example of a small group of businesses within an industrial park moving to RtR supply, the increased efficiencies with the operation of distribution infrastructure should not incur costs to be considered within the ECR framework.

Regarding **generation assets** currently owned and operated by Nova Scotia Power Inc., many of these assets could be used and maintained for Top Up/Spill operation as uptake in the RtR program increases – Scotian WindFields Inc. feels this should be considered in the ECR framework.

The legislation within the Electricity Reform Act (2013) states in section 3G (2) (a) that customers and existing IPPs are not be negatively impacted, and that all mitigating costs are to be borne by the Renewable Generator and/or the LRS. However, this legislation does not have specific provisions for costs to NSPI's existing generation fleet as a result of more competition on the Nova Scotia grid.

Scotian WindFields Inc. would like to suggest that the next step is to agree upon which categories are to be considered for ECR so that the full mechanism for this cost recovery can be decided upon.

Further, Scotian WindFields Inc. would like to request clarification from the Nova Scotia Department of Energy regarding ECR considerations.

5) Partial Service Considerations

Scotian WindFields Inc. supports the view that Partial Service was not prohibited by the legislation, although can understand the logistical and procedural challenges with a Partial Service framework for Residential and Commercial customer classes.

To this end, Scotian WindFields Inc. would like to suggest that Partial Service be considered for the Industrial Customer class, as supported by industrial customers during the December 15th Technical Conference and in section 8.3 of the December Strawman Report. Scotian WindFields Inc. feels that this is a necessary consideration to ensure program uptake with this rate class.

Based on the experiences and successes of the Partial Service operations for the Industrial rate class, Scotian WindFields Inc. proposes that Partial Service options be investigated Commercial rate classes as well; perhaps after a one to two year timeframe.

6) Other Specific Responses to NSPI Strawman and December 15th Presentation

Scotian WindFields Inc. Agrees with the three key recommendations presented on Slide 3 of the December 15th Technical Conference presentation.

Scotian WindFields Inc. Supports the Customer Service and meter ownership recommendations highlighted on Slides 4 and 6 of the December 15th Technical Conference presentation.

natural forces

Natural Forces Wind Inc. 1801 Hollis Street, Suite 1205, Halifax, Nova Scotia, Canada, B3J 3N4. Tel: +1 (902) 422 9663. Fax: +1 (902) 422 9780. www.naturalforces.ca

Linda Lefler, P.Eng.
Regulatory Project Manager
Nova Scotia Power
P.O. Box 910
Halifax, NS
B3J 2W5

9th January 2015

RE: Comments on Renewables to Retail Project ('RTR') – White Paper on Embedded Cost Recovery ('ECR') (Case M06214)

Dear Ms. Lefler,

Many thanks for the opportunity to further participate in the RTR framework development. We have structured our submission into three parts, one to further comment on the objectives of RTR, secondly to revisit some of the market design questions and thirdly to comment on the ECR White Paper.

1) Objective of RTR?

We are dissatisfied with NSPI's response to the questions put by Natural Forces and others regarding what yardstick the success or failure of the RTR program should be measured against. By NSPI and the UARB stating that this question is is not within their remit they are effectively taking no responsibility for the program's success. It can only be assumed that the legislation was enacted with a view to stimulating a RTR market and by extension that those tasked with implementing the legislation have been tasked with developing such a market. Whilst we can understand that neither NSPI nor the UARB wish to take responsibility of setting a market size independently of the Department of Energy it behooves both entities to work with the stakeholders to ask the question of Government – What is the vision for this market and what will constitute success?

2) Market Design

a) Market Structure

We note in Mr. Carey's paper on the 2nd if December he is focusing on the disaggregated tariff option. We agree with this position.

b) Meter Ownership

We are agnostic as regards meter ownership, however, the costs for the meters should be fully transparent.

c) Partial Service

We agree with the participants who supported a partial service option on the last call. Partial service was never excluded by the legislation, and should be allowed. We would be open to a minimum load size before partial service was allowed as we understand that multiple bills for a single residence would be structurally awkward.

3) White Paper on Embedded Cost Recovery

We believe that the underlying philosophy of embedded cost recovery applicable in this market transition requires a debate. Whilst we understand and acknowledge the scope of Mr. Carey's report and indeed will comment below on some of his thoughts and questions the implicit objectives of the RTR project are 1) to replace polluting generators with clean generators on the Nova Scotia electricity system and 2) to stimulate competition in the electricity sector. To this point, it is important that one realizes that when opening a market one cannot be too conservative with ECR as doing so will inhibit any market development.

a) Generation Capacity

We agree with Mr. Carey's contention that there should be no ECR recovery from stranded energy.

We note that to the extent some of the NSPI assets capacity will now be less utilized they will still be entitled to revenue under the top-up and spill tariffs that are to be determined. We are wary of the RTR customers paying twice for the same asset.

We note that Mr. Carey's suggestion that ECR should relate to NSPI assets whose utilization is reduced as a consequence of RTR and will not be receiving any revenues though other tariffs. Our comments on this item are twofold:

- How is the value of the ECR for stranded capacity calculated?

  The age of some of the assets that become stranded are such that the original invested capital will have totally paid off and if so there should be no ECR for such capacity. Any maintenance and operating costs for such assets should be recovered through the top-up and spill tariff.

- How is the capacity adequacy calculated and to what extent that is used in the ECR calculation?

  We note that Mr. Carey's contention is that the NSPI must calculate the capacity adequacy assuming 100% of the RTR energy must be able to be serviced by NSPI assets. We do not agree with this methodology as most RTR customers will be on long term contracts and as the market develops is will be very unlikely that all RTR customers choose to revert back to NSPI at the same time causing the need for all of the NSPI capacity as set out. Also it is unreasonable to expect the RTR generator to pay for 100% capacity back up through an ECR charge and also pay a top-up and spill tariff. We understand, this issue is a result of not knowing what the size of the market will be. For that reason we reiterate that goals for the opening of this market should be clearly made and from that a reasonable projection of worst case scenarios can be made.

Finally, it is interesting to note that NSPI is paying DSM to reduce the capacity needs on the system so by extension it could be argued that NSPI should also pay RTR customers for reducing capacity needs.

b) RES energy Premium

In our opinion, the concept that a RTR customer would have to pay for the contracted renewable energy NSPI has procured is not tenable. In our view, the price differential over the long term is not large and in fact through the rate case of Muskrat Falls shows that renewable energy is the lower priced option for rate payers in the long term.

- It is known from published information that the South Canoe and Sable Wind projects PPAs have a PPA price of somewhere between $70 - $74 / MWh on a 50% indexed basis. Therefore on a discounted cash flow model on a fully indexed basis the price is lower than $70/MWh.
- In understanding the Muskrat Falls cost of energy the contracted and surplus energy must be looked at together. The contracted energy is overpriced in early years but the surplus energy has been calculated off projected market rates which are most likely now well out of date given current economic circumstances in commodity markets. Thus the actual cost of this energy can only be determined over the full 35-year contract term. At a guess the price of this is also ~€70/MWh.

Therefore, given 1) it is unreasonable to expect an RTR customer to pay for the renewable attributes twice for the same energy and 2) the complexities of calculating the actual price over the long term is extremely difficult and when calculated is likely to be close to the marginal cost for NSPI, we do not believe that ECR should include a RES energy premium.

Finally, we understand that in other market transitions fuel contracts are not part of an ECR calculation. Why should long term renewable contracts be treated any differently?

c) Transmission

We understand the approach taken my Mr. Carey that even though RTR generation and an RTR customer would be in the same distribution zone that transmission charges would still be appropriate as NSPI would have to allow for the back-up capacity on the transmission system in the event that the RTR generation was unavailable. The only comment we have is that to the extent a transmission charge is applied it should be fairly applied to all system participants.

d) Fuel Adjustment Mechanism

We propose that this charge can be put on the RTR only if it has been approved before the RTR customer exits.

e) Embedded Deferrals

Embedded deferrals should not be considered stranded, unless it can be demonstrated that they would not have been required if the RTR customer had not been in the system.

f) Embedded Cost Recovery Mechanisms

We propose that in determining the Embedded Cost Recovery mechanism the following principals should be adopted:

- That the costs to the RTR customer is fixed at the time of exit;
- That the costs could be spread out over a period to avoid a lump sum payment at exit;
- That the costs are transparently determined and approved by the UARB; and
- That new customers to the system should not be liable for ECR charges.

We thank NSPI for the opportunity to comment on the market design white paper and look forward to further engaging as the project develops. We remain available at all times for further consultation.

Yours sincerely,

John A. Brereton

President

Nova Scotia POWER
An Emera Company

FEBRUARY 12, 2015

Renewable to Retail Project

Rate Setting at NS Power

energy everywhere.™

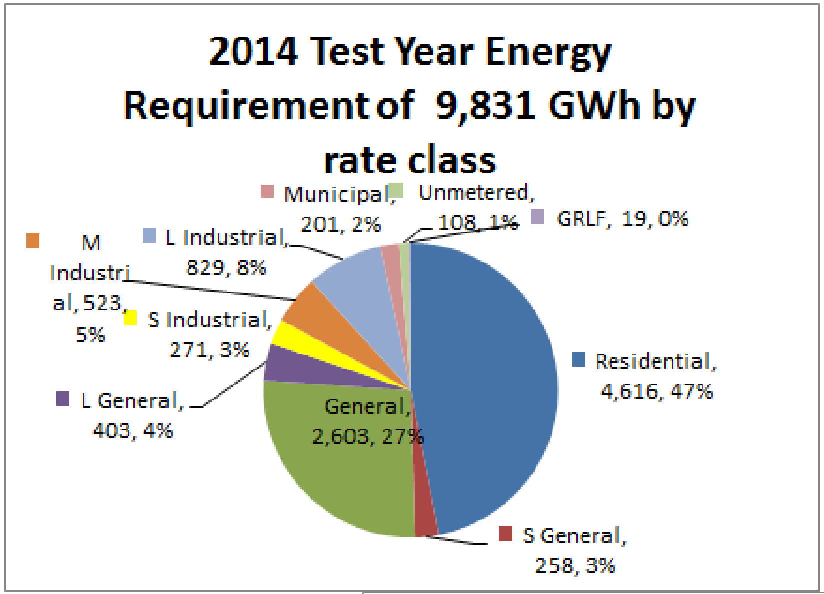
Objectives of Price Regulation: just and reasonable rates

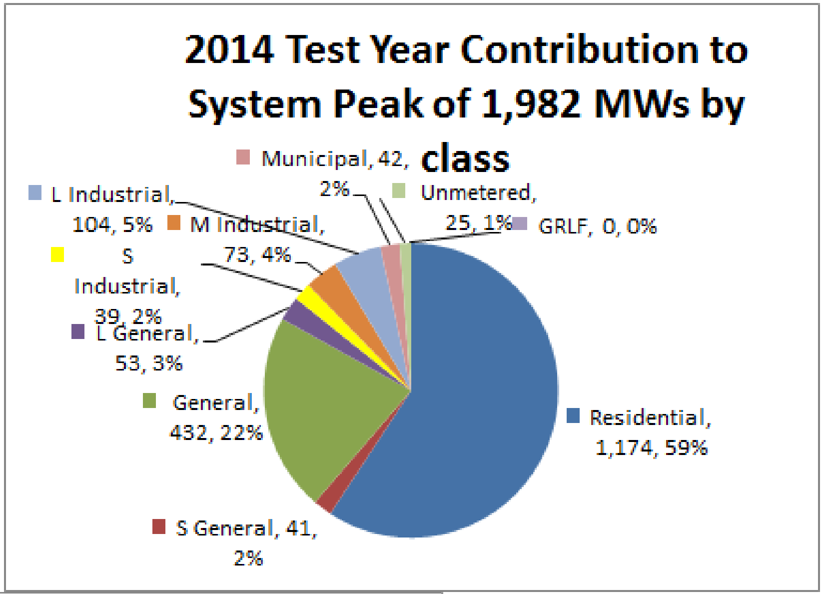
- Regulation a substitute for competition
- Rate setting a balancing act among various interests
  - Utility has an opportunity to
    - Recover prudently incurred costs
    - Earn allowable rate of return on used and useful investments
  - Customer rates are based on cost causation principle
    - To the extent practical, the costs should be recovered from those who caused them.
    - Difference in service characteristics may lead to rates based on different cost standards, such as embedded vs. marginal cost based rates
    - Cost-based rates are synonymous with equity; however fairness, reflective of broader public interest, may justify a departure from costs
      - » Revenue to Cost Ratios, Load Retention Rates, Rate Stabilization Plans resulting in cost deferrals which will vary by class and type of rate: GRA – General Rate Application; FAM - Fuel Adjustment Mechanism; DSM – Demand Side Management; AAR - Annually Adjusted Rates; OATT – Open Access Transmission Tariff

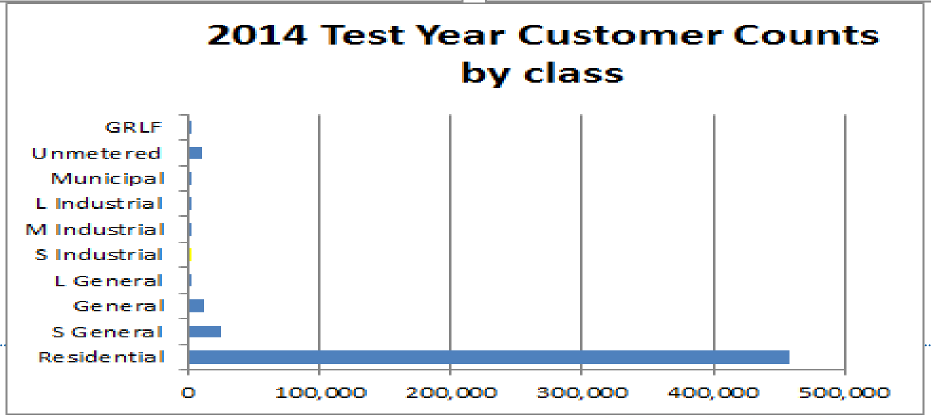
Electric service in context of cost causation

- Utility is under obligation to serve, subject to various quality standards
- Electric Service Components
  - kW or kVA Demand System Peaks
  - kWh Energy
  - Customer Services (information services, metering, billing, etc.)
- Key Cost Causation Factors
  - Consumption: volume, patterns, power factors
  - Firm vs. interruptible
  - Point of Delivery: distribution versus transmission
  - Customer Care: billing, metering, call center, etc.
  - Other Services: street and area lighting, pole attachments, wiring inspections, connection/disconnections, load research info, DSM, etc.

Electric service in 2014 Test Year







energy everywhere.™

Nova Scotia POWER An Emera Company

Prospective Rate Setting Process

Price Level
The total amount of revenue Required to recover test year costs.

Revenue Requirement

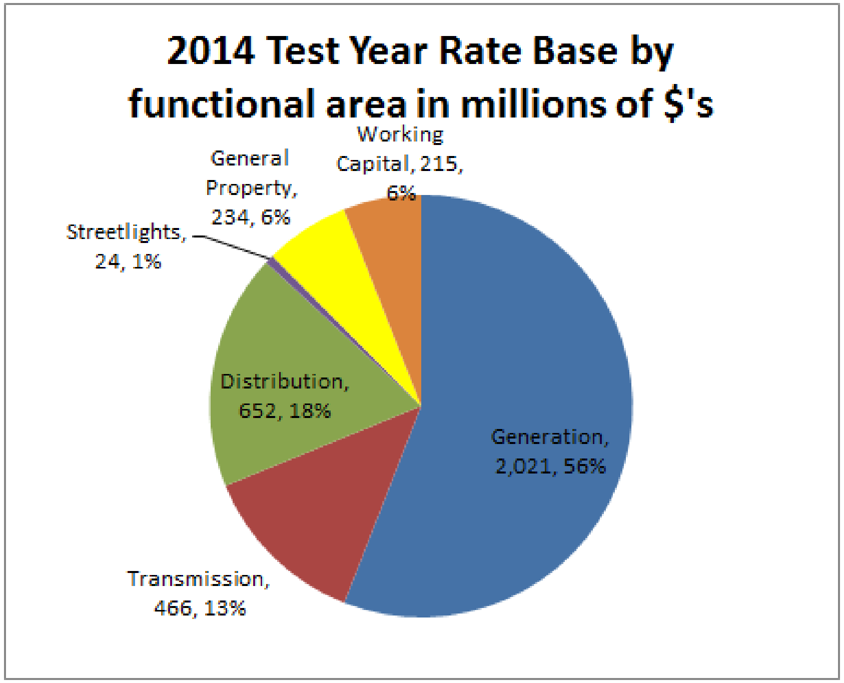
Cost Allocation
The amount of total costs to be allocated to individual rate classes.

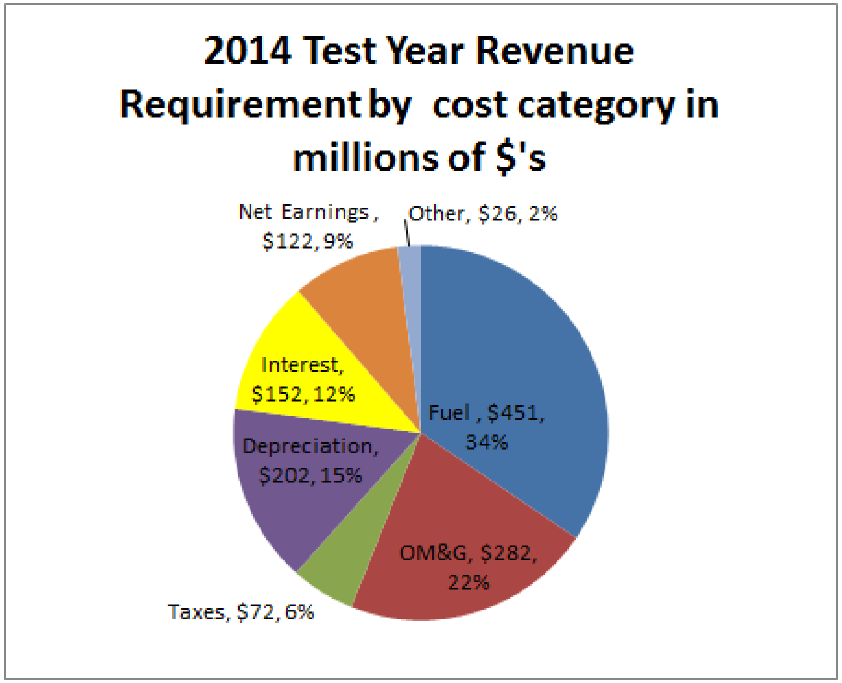
Cost of Service

Revenue responsibilities
Determines the revenue responsibilities among rate classes and individual customers.

Rate Design

Revenue Requirement





- The books and records of the Company, save dedicated facilities, are not kept at a rate class level, so class level costs must be developed.

Cost of Service Studies

The Cost of Service Study is a process used by a utility to apportion utility's costs among customer classes for the purpose of development of rates.

- To the extent practical direct assignment of costs is preferred over allocation. However, most of the infrastructure is shared and costs of service to customer classes cannot be tracked in company's records.
- Shared costs are apportioned on the basis of cost causation as determined by asset or service utilization using a three step process.
  1. Functionalizing rate base and costs among Generation, Transmission, Distribution and Retail
  2. Classifying rate base and costs among energy-, demand- and customer-related services
  3. Allocation of responsibility for utilization of rate base and incurred costs based on usage of these services by rate classes

energy everywhere.™

Nova Scotia POWER An Emera Company

2013 Generic Cost of Service Proceeding

- *UARB Decision:*

"This was the first comprehensive COSS review since 1995. However, as a whole, the results of this process confirmed that the existing cost of service was not significantly out of balance."

energy everywhere.™

Nova Scotia POWER An Emera Company

2014 Test Year Cost of Service Study Results by Functional Area

RATE CLASS	(1) GWh SALES	(2) TOTAL COSTS GENER. EXPENSES	(3) TRANS. EXPENSES	(4) DISTR. EXPENSES	(5) RETAIL EXPENSE	(6) COST OF SERVICE	(7) UNIT COSTS IN CENTS PER KWh GENER.	(8) TRANS.	(9) DISTR.	(10) RETAIL	(11) TOTAL W. AVE.
(1) DOMESTIC	4,217	$458,553	$55,260	$122,428	$42,045	$678,286	10.88	1.31	2.90	1.00	16.09
(2) SMALL GENERAL	237	$23,673	$2,589	$6,686	$2,498	$35,447	10.00	1.09	2.83	1.06	14.98
(3) GENERAL	2,449	$242,184	$27,036	$35,084	$3,158	$307,462	9.89	1.10	1.43	0.13	12.56
(4) LARGE GENERAL	380	$35,953	$3,792	$2,402	$366	$42,512	9.47	1.00	0.63	0.10	11.20
(5) SMALL INDUSTRIAL	256	$24,407	$2,612	$3,866	$661	$31,546	9.54	1.02	1.51	0.26	12.33
(6) MEDIUM INDUSTRIAL	495	$47,065	$5,045	$4,441	$582	$57,132	9.50	1.02	0.90	0.12	11.53
(7) LARGE INDUSTRIAL (1)	793	$68,346	$7,683	$1,317	$968	$78,313	8.62	0.97	0.48	0.12	9.88
(8) ELI 2P-RTP	-					$0	NA	NA	NA	NA	NA
(9) MUNICIPAL (1)	192	$19,259	$2,225	$801	$235	$22,520	10.01	1.16	0.64	0.12	11.71
(10) UNMETERED	98	$10,463	$1,224	$11,122	$1,117	$23,926	10.65	1.25	11.32	1.14	24.35
(11) TOTAL ATL	9,116	$929,904	$107,466	$188,147	$51,629	$1,277,146	10.20	1.18	2.06	0.57	14.01
(12) RELATIVE SHARES		73%	8%	15%	4%	100%	73%	8%	15%	4%	100%

Footnotes
(1) Unit Distribution Costs calculated on the basis of distribution connected class load

energy everywhere.™

Nova Scotia POWER An Emera Company

2014 Test Year Results: Cost of Service and Revenue Responsibility

RATE CLASS	(1) GWh SALES	(2) DEMAND RELATED EXPENSES	(3) ENERGY RELATED EXPENSES	(4) CUSTOMER RELATED EXPENSES	(5) TOTAL COST OF SERVICE	(6) TOTAL REVENUE	(7) UNIT COST (C / kW.h)	(8) UNIT REVNUE (C / kW.h)	(9) REVENUE TO COST RATIO(1)
(1) DOMESTIC	4,217	$199,348	$383,249	$95,689	$678,286	$672,437	16.09	15.95	99.14
(2) SMALL GENERAL	237	8,733	21,408	5,306	35,447	37,000	14.98	15.63	104.38
(3) GENERAL	2,449	84,713	215,788	6,962	307,462	318,043	12.56	12.99	103.44
(4) LARGE GENERAL	380	8,724	33,414	374	42,512	42,341	11.20	11.15	99.60
(5) SMALL INDUSTRIAL	256	7,699	22,443	1,405	31,546	32,513	12.33	12.71	103.07
(6) MEDIUM INDUSTRIAL	495	13,243	43,253	636	57,132	55,016	11.53	11.11	96.30
(7) LARGE INDUSTRIAL	793	8,757	68,575	981	78,313	74,836	9.88	9.44	95.56
(8) ELI 2P-RTP	-	0	0	0	0	0	NA	NA	NA
(9) MUNICIPAL	192	5,588	16,694	239	22,520	21,170	11.71	11.01	94.01
(10) UNMETERED	98	13,021	8,976	1,929	23,926	23,789	24.35	24.21	99.43
(11) TOTAL ATL	9,116	$349,825	$813,800	$113,521	1,277,146	1,277,146	14.01	14.01	100.00
(12) RELATIVE SHARES		27%	64%	9%	100%				

Footnotes
(1)Test Year Revenues and R/C ratios were set based on the COSS from the 2013 GRA, now replaced by a new COSS.

energy everywhere.™

Nova Scotia POWER An Emera Company

Bundled Service Rate Components[1]

RATE CLASS	(1) CUSTOMER CHARGE $/Month	(2) DEMAND CHARGE $/KVA[2]	(3) ENERGY CHARGES IN CENTS PER KWh: FLAT	(4) DECLINING BLOCK RATES[1]: FIRST 200 KWh	(5) DECLINING BLOCK RATES[1]: TAIL BLK	(6) TIME OF DAY RATES: ON-PEAK	(7) TIME OF DAY RATES: SHOULDER	(8) TIME OF DAY RATES: OFF-PEAK
(1) DOMESTIC NON-TOD	$10.83	NA	14.251	NA	NA	NA	NA	NA
(2) DOMESTIC TOD	$18.82	NA	NA			18.609	14.251	7.324
(2) SMALL GENERAL	$12.65	NA	NA	15.092	13.278	NA	NA	NA
(3) GENERAL[2]	NA	$10.497	NA	11.208	7.929	NA	NA	NA
(4) LARGE GENERAL	NA	$13.345	8.029	NA	NA	NA	NA	NA
(5) SMALL INDUSTRIAL	NA	$7.714	NA	10.090	7.707	NA	NA	NA
(6) MEDIUM INDUSTRIAL	NA	$12.501	7.241	NA	NA	NA	NA	NA
(7) LARGE INDUSTRIAL FIRM	NA	$11.995	7.620	NA	NA	NA	NA	NA
(7) LARGE INDUSTRIAL INT	NA	$8.565	7.222	NA	NA	NA	NA	NA
(8) ELI 2P-RTP	NA	NA	NA	NA	NA	NA	NA	NA
(9) MUNICIPAL	NA	$12.445	7.539	NA	NA	NA	NA	NA
(10) UNMETERED[3]	NA	$11.777	NA	13.467	8.941	NA	NA	NA

Footnotes
(1) Capped at 3% increase per year under the 2 Year Rate Stabilization Plan
(2) Where demand charge is in effect the first block is 200 KWh * kW or KVA
(3) For the General Class the Demand Charge applies to kW
(4) The electric service portion of Miscellaneous Load Rate

Bundled Service vs Open Access

Questions

energy everywhere.™

Nova Scotia POWER An Emera Company

Nova Scotia POWER
An Emera Company

THURSDAY, FEBRUARY 12, 2015

Renewable to Retail Project

Background Information on Market Rules, OATT, GIP, & Backup/Top-up Service

Outline

1. Overview of Existing Market
2. Open Access Transmission
3. Generator Interconnection
4. Top Up / Back Up / Spill Tariffs

Nova Scotia POWER
An Emera Company

THURSDAY, FEBRUARY 12, 2015

1. Market Overview

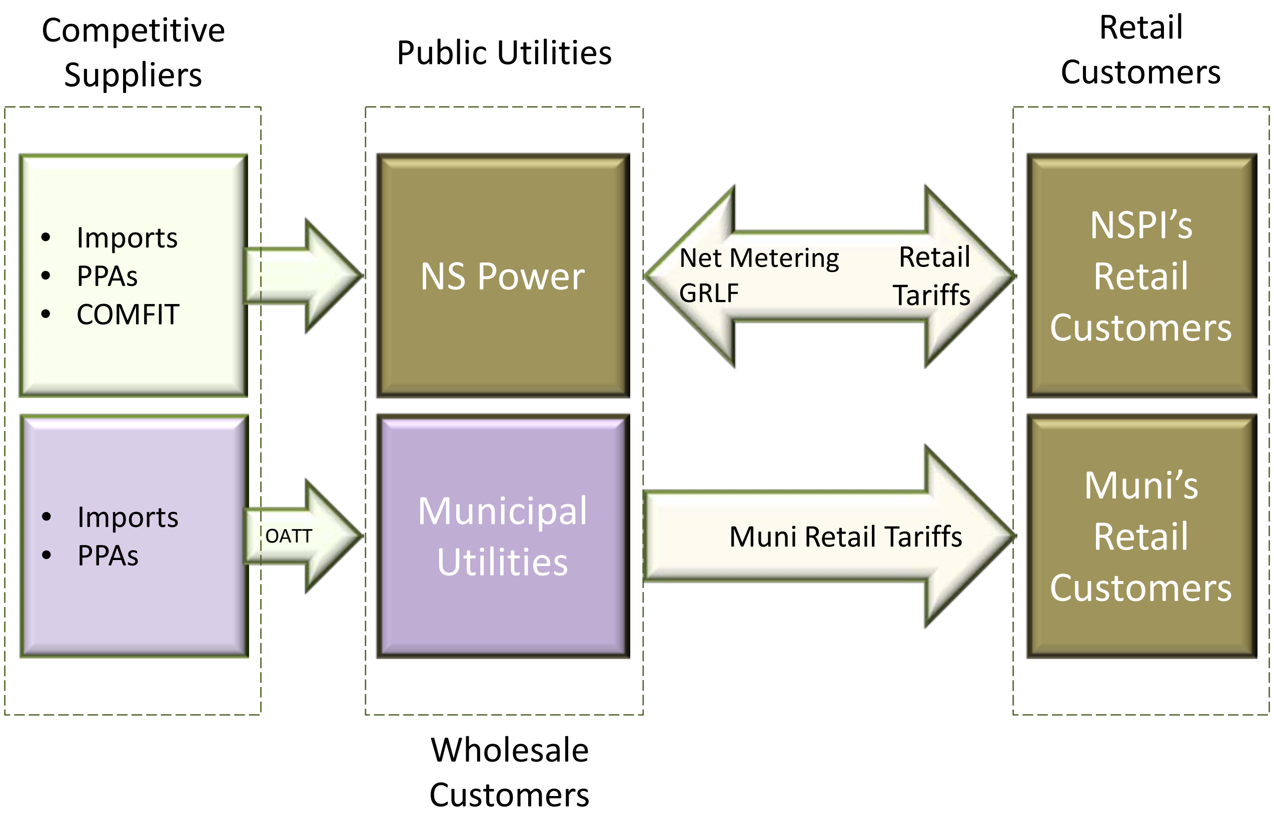
Current Market Structure

There are two electricity markets operating within NS:

- Regulated retail market: Retail customers obtain service from regulated utilities using UARB approved Rates, Tariffs and Regulations, and;
- Competitive Wholesale Market: Eligible customers arrange bilateral transactions with a supplier, or suppliers for all or part of their energy needs.
  - These suppliers may be located inside or outside of NS.
  - The Wholesale Market is supported by a UARB-approved, cost-based, Open Access Transmission Tariff (OATT).
- The *Electricity Act*, which opened the Nova Scotia electricity market to wholesale competition, went into effect on February 1, 2007.

Nova Scotia POWER An Emera Company

Current NS Electricity Markets

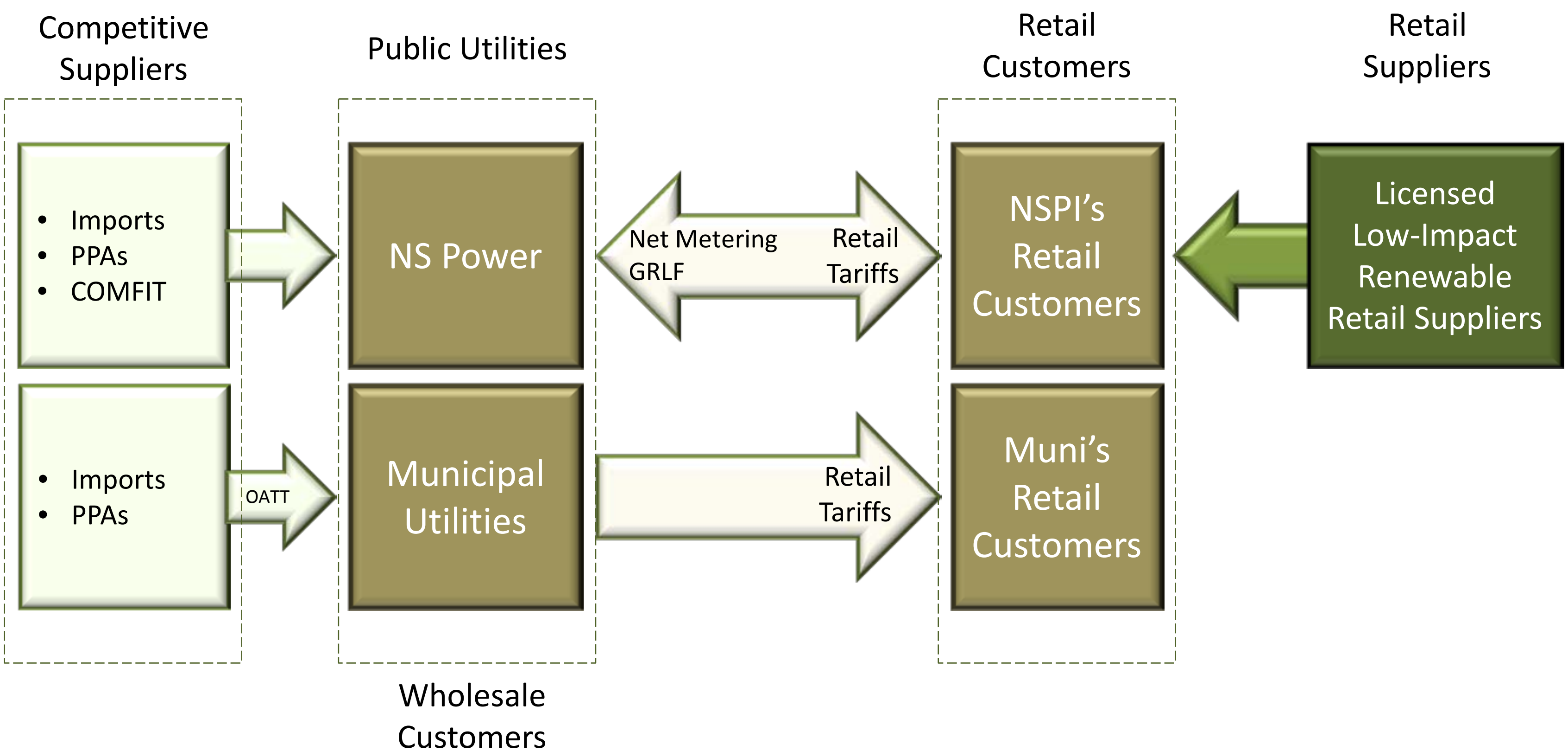


The Renewable to Retail Market Opening

- Electricity Reform Act (2013)
- Provides NS Power's customers with a choice for their electricity provider
- Will allow our retail customers to purchase renewable low-impact electricity (e.g.. wind, solar, biomass, tidal) generated in Nova Scotia from a competitive supplier
- Suppliers will be licensed by the NSUARB.
- Only NS Power's retail customers can participate - Municipal Electric Utility customers are excluded
- The existing regulated retail and competitive wholesale markets will continue.

Nova Scotia POWER An Emera Company

The NS Electricity Market Opening



Nova Scotia POWER
An Emera Company

THURSDAY, FEBRUARY 12, 2015

Wholesale Electricity Market Rules

Nature and scope of the Nova Scotia Wholesale Electricity Market

- The Nova Scotia wholesale electricity market is a Bilateral Market.
- Eligible buyers and sellers can enter into bilateral transactions for the purchase and sale of electricity and related services and schedule their transactions over NS Power's Transmission System.
- The Open Access Transmission Tariff and these Market Rules govern how such transactions are to be scheduled and executed.
- Eligible generators may participate in this wholesale market and may sell certain Ancillary Services to the Nova Scotia Power System Operator (NSPSO)

Nova Scotia POWER An Emera Company

Object and Purpose of the Wholesale Market Rules

The promotion of economical supply via competitive opportunity amongst eligible participants within a safe and reliable Nova Scotia electricity system.

The Market Rules define the rights and obligations of the NSPSO towards Market Participants, and of Market Participants towards the NSPSO…

- in respect of the market
- in the administration of the Transmission Tariff
- and the operation of the Bulk Electricity Supply System.

Nova Scotia POWER An Emera Company

Nova Scotia Power System Operator

- Responsible for the safe and reliable operation of the Bulk Electricity Supply System.
- Act as the Market Administrator
- NSPSO operates in a manner that is:
  - non-discriminatory,
  - transparent,
  - robust, and
  - efficient
  - subject to and in accordance with all Legislation and Regulations, the Transmission Tariff, the Standards of Conduct, and the Market Rules.

Nova Scotia POWER An Emera Company

NSPSO Responsibilities are:

a) the specific responsibilities of the NSPSO stated in the Market Rules;

b) the responsibilities of NS Power to

i) file amendments to the Transmission Tariff,

ii) provide transmission service under the Transmission Tariff,

iii) provide Ancillary Services under the Transmission Tariff,

iv) operate the Transmission System in accordance with the Transmission Tariff, and

v) schedule transactions on the interconnections between Nova Scotia and New Brunswick;

- other responsibilities consistent with Legislation and Regulations, with the Transmission Tariff, with the Standards of Conduct and with the Market Rules, that may be assigned by NS Power.

Nova Scotia POWER An Emera Company

Wholesale Market Rules contents

1. Introduction
2. Market Administration
3. Reliability Planning Requirements
   - From 10 years to month ahead (+ outage management)
4. Wholesale Market Operations
   - Week ahead to real time
5. Settlement
   - After dispatch

Nova Scotia POWER An Emera Company

Wholesale Market Advisory Committee
(MR Ch. 2, App 2C)

The WMAC advises the NSPSO in matters of the NS wholesale Electricity Market and is the main forum for active consultation with stakeholders on the following:

i) Proposed amendments to Market Rules
ii) New or amended standards, codes or Market Procedures
iii) Other wholesale electricity market issues identified by the NSPSO, committee members, or other stakeholders.

The WMAC provides an opportunity for discussion of proposed changes to the OATT under consideration by the NSPSO in preparation for application to the Board.

Nova Scotia POWER An Emera Company

Wholesale Market Advisory Committee

Membership of the Wholesale Market Advisory Committee includes:

a) one representative of the NSPSO who shall be chair;
b) one representative of NS Power, Power Production;
c) one representative of NS Power, Customer Service;
d) one representative of independent generators;
e) one representative of those eligible to be Market Participants as wholesale loads; and
f) one representative of those otherwise eligible to be Transmission Customers.

Nova Scotia POWER An Emera Company

Standards of Conduct

FERC Order 889 (1996):

- to support wholesale competition in electricity markets
- to ensure TP's don't use their information unfairly to favor their own (or affiliate) merchant functions in selling electric energy.
- To ensure equal access to transmission system information
- To ensure that TP's Transmission employees function independently from TP's Wholesale Merchant employees
- To enable vertically integrated utilities to participate in open markets (Otherwise a separate independent System Operator would be required)

Standards of Conduct General Rules

- Transmission Function employees must function independently of Nova Scotia Power's Marketing and Sales employees *(Power Production/generation /commercial operations, FERM, and from any employees of its affiliates)*
- Transmission Function employees must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and must not operate its transmission system to preferentially benefit an affiliate.

Nova Scotia POWER
An Emera Company

THURSDAY, FEBRUARY 12, 2015

NS Power
Open Access Transmission Tariff

NS Utility & Review Board Order P-880

- P-880, dated May 31, 2005, approved both the Open Access Transmission Tariff (OATT) and the Standard (Generator) Interconnection Procedures (GIP)
- The OATT defined the transmission access services offered by NS Power and detailed the prices charged for each service
- The GIP defined the processes required to interconnect a transmission generating facility to the NS Power Transmission System

Nova Scotia POWER
An Emera Company

http://oasis.nspower.ca/en/home/oasis/default.aspx

Nova Scotia POWER An Emera Company

OASIS
OPEN ACCESS SAME-TIME INFORMATION SYSTEM

OASIS

Home » Oasis

- » TRANSMISSION CUSTOMER PROCEDURES
- » GENERATION INTERCONNECTION PROCEDURES
- » SYSTEM REPORTS AND MESSAGES
- » MONTHLY REPORTS
- » STANDARDS OF CONDUCT
- » WHOLESALE MARKET DOCUMENTS
- » REGULATORY DOCUMENTS
- » STANDARDS AND CODES
- » CALENDARS
- » FORECASTS AND ASSESSMENTS

OASIS

Open Access Same-time Information System (OASIS)

The Nova Scotia Power Open Access Transmission Tariff (OATT) came into effect on November 1st, 2005. For OATT-related documents see the Transmission Customer Procedures and Generation Interconnection Procedures sections in the menu on the left.

The Electricity Act came into effect on February 1, 2007. For details, choose the Wholesale Market Documents section in the menu on the left.

Transmission Services:

- OASIS Reservation Web Site (Secure Site - registration required)

Apply for access to OASISNova Scotia Power has contracted the New Brunswick System Operator (NBSO) to manage its OASIS reservation web site. To become a registered user of the NSP OASIS, click here and follow the steps as outlined on the NBSO site.

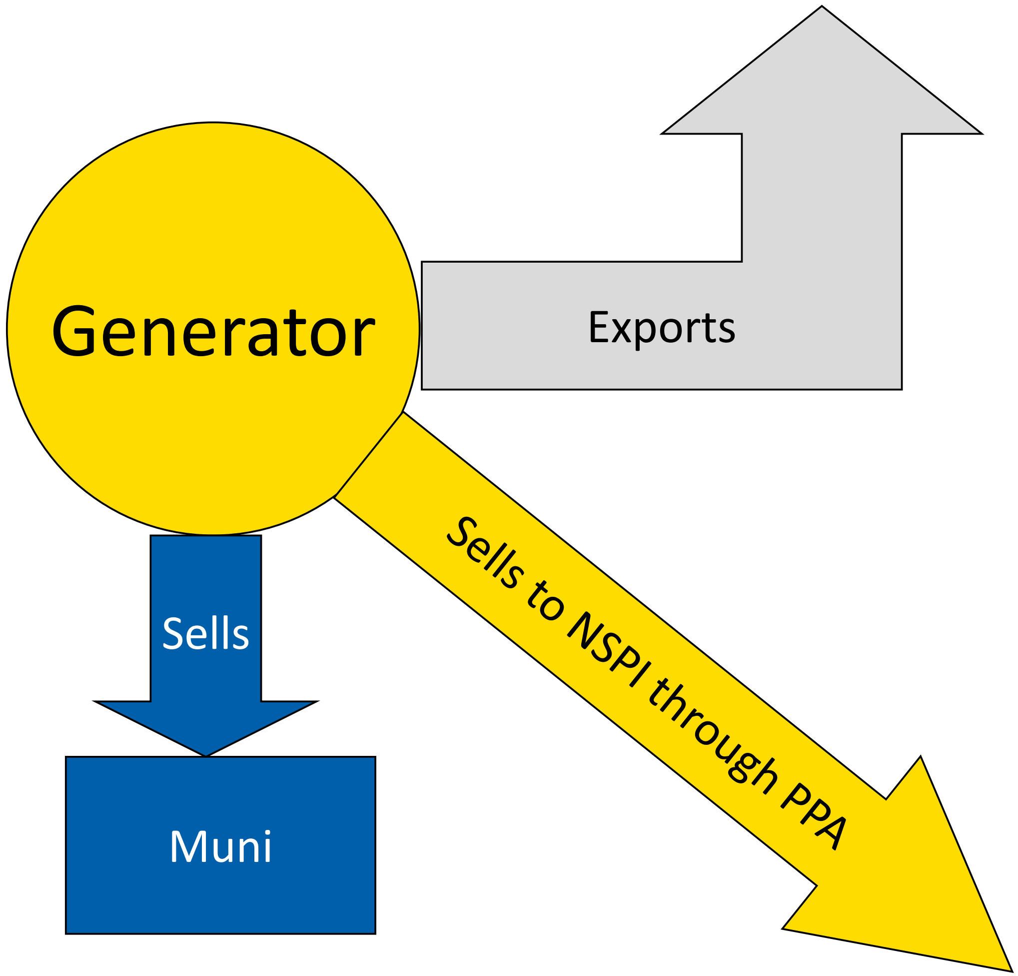
- Open Access Transmission Tariff (OATT), including schedules and attachments (PDF)
  - Open Access Transmission Tariff 2013 Schedules (PDF)
  - Open Access Transmission Tariff 2014 Schedules (PDF)
- Transmission System Information Request (PDF)

Who is Eligible?

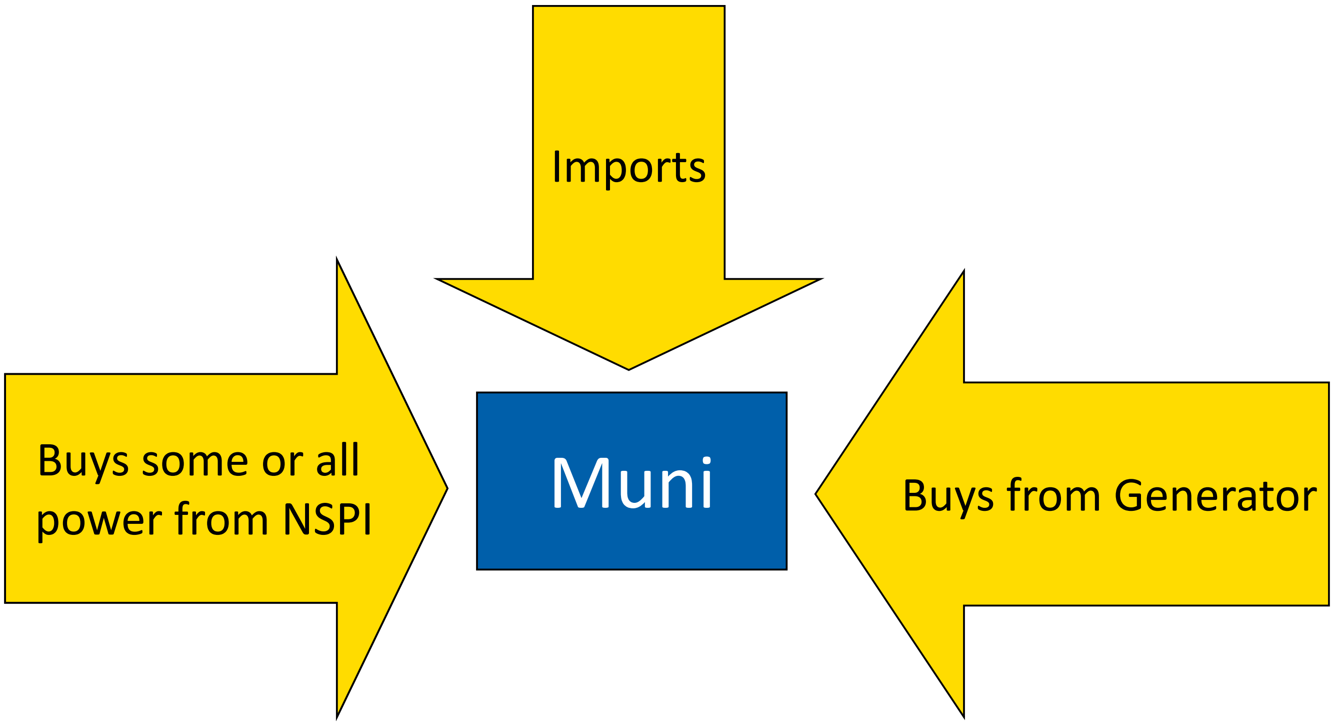
- NS Power
- Municipal electrical utilities
- Electricity suppliers outside NS to provide service to eligible customers
- Generators connected to the NS Power grid to
  - sell electricity to the municipal utilities or
  - export electricity to other jurisdictions

Nova Scotia POWER An Emera Company

Transactions – Generators



Transactions – Muni's



Nova Scotia POWER An Emera Company

What OATT Service do Customers Take?

- ***"Point-to-Point"*** Transmission Service – path specific, firm or non-firm, short-term or long term. Customer pays for transmission services based on the "reserved amount".
- ***"Network"*** Transmission Service – an annual, firm service. Customer buys energy from any eligible generator, and pays NS Power for transmission services based on the monthly peak demand of its meter.
- ***Ancillary Services*** - are required for both types of transmission service.

Ancillary Services

Service	Exporter	In-province load
Scheduling/Dispatch/ System Control	Mandatory from NS Power	Mandatory from NS Power
Reactive Supply and Voltage Control	Mandatory from NS Power	Mandatory from NS Power
Regulation & Frequency Response	N/A	NS Power or 3rd party
Energy Imbalance	N/A	NS Power or 3rd party
Operating Reserve – Spinning	N/A	NS Power or 3rd party
Operating Reserve – Supplemental	N/A	NS Power or 3rd party

Nova Scotia POWER An Emera Company

Losses - Network Service

- Network Loads must include losses in their transaction schedule.
- System Average Loss Factor used for all Network Service customers – regardless of location
- Loss factors are updated annually and posted on OASIS. Current factor is 2.28% of load

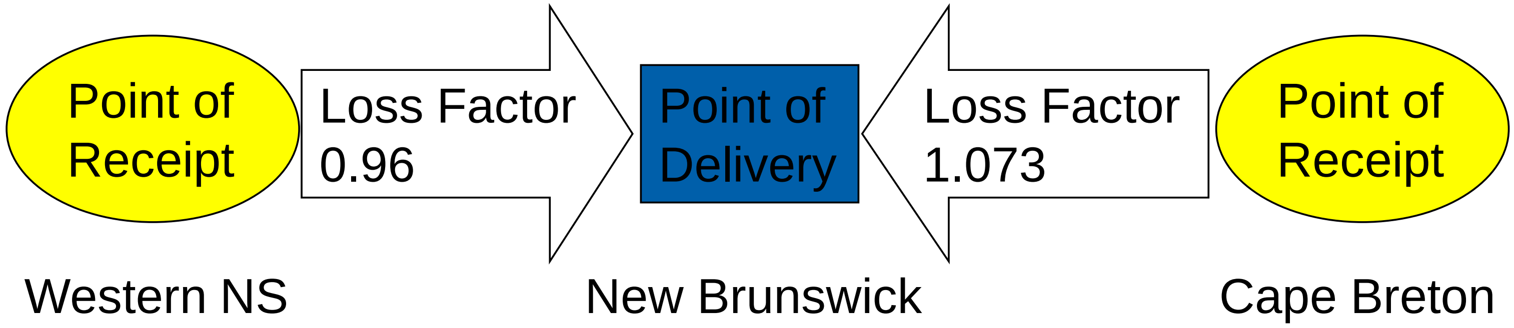
Example:

Network Load forecasted to be 40 MW submits a "balanced schedule" showing 41MW of generation.

Nova Scotia POWER An Emera Company

Losses – Point-to-Point Service

- System Operator will seasonally calculate losses for each path designated on OASIS.
- Path has a Point of Receipt and Point of Delivery.
- Transaction can increase or decrease total system losses (Loss Factor greater than or less than 1.00)



Partial Service

- FERC *pro forma* required load at a single delivery point to be served 100% (or not at all) under OATT.
- NS Power included partial service allowing the Municipal Electric Utilities to take service from both NS Power and a third party.
- A customer taking partial service must:
  - Designate the portion of load (both demand and energy) to be supplied from a third party and/or from NS Power.
  - Pay for the portion to be taken from NS Power at the appropriate bundled rate.

Billing Determinants

- The billing determinant for point-to-point service is the transmission capacity reserved.
- The billing determinant for network service is the customer's monthly non-coincident peak (NCP)

Nova Scotia POWER An Emera Company

OATT Schedules

OATT Schedule Costs - 2014					
Schedule	Description	Costs / Month / MW		% / MW	
		Network	Point to Point	Network	Point to Point
1	Scheduling, System Control, Dispatch	$353.98	$416.45	5.40%	5.63%
2	Reactive Supply & Voltage Control	$182.76	$214.97	2.79%	2.91%
3	Regulation	$217.06	$217.06	3.31%	2.94%
	Load Following	$776.85	$776.85	11.86%	10.51%
4	Energy Imbalance	-	-	-	-
5	Operational Reserve - Spinning	$166.58	$166.58	2.54%	2.25%
6a	Operational Reserve - 10 minute	$331.83	$331.83	5.06%	4.49%
6b	Operational Reserve - 30 minute	$281.23	$281.23	4.29%	3.80%
7	Firm Point to Point Transmission Service	-	$4,989.66	-	67.48%
8	Non-Firm Point to Point Transmission Service	-	$4,989.66	-	67.48%
9	Real Power Loss Factor	-	-	-	-
10	Network transmission Service	$4,241.21	-	64.74%	-
	Total	$6,551.50	$7,394.63	100.00%	100.00%

The TC must take ancillary services items 1 & 2

The TC may self supply ancillary services items 3-6

Total amount shown assumes **no** self supply of ancillary services by TC

Nova Scotia POWER An Emera Company

3MW Network Service

OATT Schedule Costs - 2014		3MW Network Service		
Schedule	Description	Costs / Month / MW Network	Cost/Month $	% / MW Network
1	Scheduling, System Control, Dispatch	$353.98	$1,061.94	5.40%
2	Reactive Supply & Voltage Control	$182.76	$548.28	2.79%
3	Regulation	$217.06	$651.18	3.31%
	Load Following	$776.85	$2,330.55	11.86%
4	Energy Imbalance	-	-	-
5	Operational Reserve - Spinning	$166.58	$499.74	2.54%
6a	Operational Reserve - 10 minute	$331.83	$995.49	5.06%
6b	Operational Reserve - 30 minute	$281.23	$843.69	4.29%
10	Network transmission Service	$4,241.21	$12,723.63	64.74%
	Total	$6,551.52	$19,654.50	100.00%

Nova Scotia POWER
An Emera Company

3MW Point to Point Service

OATT Schedule Costs - 2014		3MW Point to Point Service		
Schedule	Description	Costs / Month / MW Point to Point	Cost/Month $	% / MW Point to Point
1	Scheduling, System Control, Dispatch	$416.45	$1,249.35	5.63%
2	Reactive Supply & Voltage Control	$214.97	$644.91	2.91%
3	Regulation	$217.06	$651.18	2.94%
	Load Following	$776.85	$2,330.55	10.51%
4	Energy Imbalance	-	-	-
5	Operational Reserve - Spinning	$166.58	$499.74	2.25%
6a	Operational Reserve - 10 minute	$331.83	$995.49	4.49%
6b	Operational Reserve - 30 minute	$281.23	$843.69	3.80%
7	Firm Point to Point Transmission Servic	$4,989.66	$14,968.98	67.48%
8	Non-Firm Point to Point Transmission S	$4,989.66		67.48%
	Total	$7,394.63	$22,183.89	100.00%

Nova Scotia POWER An Emera Company

THURSDAY, FEBRUARY 12, 2015

NS Power Generator Interconnection Procedures

Generator Interconnections

Distribution Connected (Below 69 kV – typically 25kV and below)		Transmission Connected (69 kV and above)
Under 100 kW Class 1	Over 100 kW Class 2 Distribution Interconnection Procedures (DGIP)	Generator Interconnection Procedures (GIP)

Generator Interconnection Procedures

- Allows non-discriminatory access to NS Power transmission system (69kV or above) while protecting reliability
- Applies to new generating facilities & increases in capacity to existing generating facilities
- Includes an Interconnection Queue; study procedures; and standard GIA template
- Revised on Feb 10, 2010 to reflect a "First ready, first served" model

(http://oasis.nspower.ca/en/home/default/oasis/default.aspx)

Nova Scotia POWER An Emera Company

http://oasis.nspower.ca/en/home/oasis/default.aspx

Nova Scotia POWER An Emera Company
OASIS
OPEN ACCESS SAME-TIME INFORMATION SYSTEM
OASIS

Home » Oasis

» TRANSMISSION CUSTOMER PROCEDURES
» GENERATION INTERCONNECTION PROCEDURES
» SYSTEM REPORTS AND MESSAGES
» MONTHLY REPORTS
» STANDARDS OF CONDUCT
» WHOLESALE MARKET DOCUMENTS
» REGULATORY DOCUMENTS
» STANDARDS AND CODES
» CALENDARS
» FORECASTS AND ASSESSMENTS

OASIS

Open Access Same-time Information System (OASIS)

The Nova Scotia Power Open Access Transmission Tariff (OATT) came into effect on November 1st, 2005. For OATT-related documents see the Transmission Customer Procedures and Generation Interconnection Procedures sections in the menu on the left.

The Electricity Act came into effect on February 1, 2007. For details, choose the Wholesale Market Documents section in the menu on the left.

Transmission Services:

- OASIS Reservation Web Site (Secure Site - registration required)

Apply for access to OASISNova Scotia Power has contracted the New Brunswick System Operator (NBSO) to manage its OASIS reservation web site. To become a registered user of the NSP OASIS, click here and follow the steps as outlined on the NBSO site.

- Open Access Transmission Tariff (OATT), including schedules and attachments (PDF)
  - Open Access Transmission Tariff 2013 Schedules (PDF)
  - Open Access Transmission Tariff 2014 Schedules (PDF)
- Transmission System Information Request (PDF)

Nova Scotia POWER An Emera Company

Nova Scotia POWER An Emera Company OASIS OPEN ACCESS SAME-TIME INFORMATION SYSTEM

OASIS

Home » Oasis » Generation Interconnection Procedures

- » TRANSMISSION CUSTOMER PROCEDURES
- » GENERATION INTERCONNECTION PROCEDURES
- » SYSTEM REPORTS AND MESSAGES
- » MONTHLY REPORTS
- » STANDARDS OF CONDUCT
- » WHOLESALE MARKET DOCUMENTS
- » REGULATORY DOCUMENTS
- » STANDARDS AND CODES
- » CALENDARS
- » FORECASTS AND ASSESSMENTS

GENERATION INTERCONNECTION PROCEDURES

The following procedures, agreements and forms are required to initiate the various interconnection studies and processes required through NSP's Generator Interconnection Procedures. All completed forms should be **sent** to:

Nova Scotia Power Inc.
5 Long Lake Drive
Halifax, NS, Canada
B3S 1N8
Attention: Mehran Zamani, Interconnection Engineer.

Interconnection Engineer can be reached at: (902) 428-3000 X 5416

Transmission Interconnection Procedures (Applicable to transmission systems 69,000 volts and higher)

- GIP Study Calendar
- Standard Generation Interconnection Procedures (PDF)
- Generator Interconnection Request Form - Appendix 1 (PDF)
- Feasibility Study Agreement - Appendix 2 (PDF)
- System Impact Study Agreement - Appendix 3 (PDF)
- Facilities Study Agreement - Appendix 4 (PDF)
- Optional Study Agreement - Appendix 5 (PDF)
- Standard Generator Interconnection and Operating Agreement (GIA) - Appendix 6 (PDF)

GIP

Interconnection Request Queue

- Combined T/D Advanced Stage Interconnection Request Queue (PDF)
- Active Transmission Interconnection Requests (PDF)
- Active Distribution Interconnection Requests (PDF)

Queue

Distribution Generator Interconnection Procedures (Applicable to distribution systems 26,400 volts and lower) - Effective July 8, 2011

- DGIP Study Calendar
- Overview of Distribution Generator Interconnection Process (>=101kW) (PDF)
- Distribution Generator Interconnection Procedures (PDF)
- Distribution Generator Interconnection Request Form - DGIP Appendix 1 (PDF)
- Distribution System Impact Study Agreement - DGIP Appendix 2 (PDF)
- Optional Distribution System Impact Study Agreement - DGIP Appendix 3 (PDF)
- Standard Small Generator Interconnection and Operating Agreement (SSGIA) - DGIP Appendix 4 (PDF)

DGIP

Nova Scotia POWER An Emera Company

Generator Interconnection Procedures

- In the Wholesale Market environment, the GIP accommodated Generator access to the NS Power transmission system for sale of energy to NS Power via a PPA; to the Municipal Utilities identified in the Electricity Act via a PPA; and to accommodate export of generation via an associated transmission service request.
- It does not accommodate direct to retail sales of energy or capacity from Generators.

Nova Scotia POWER An Emera Company

Queuing Principles

- Public posting on OASIS with Initial and Advanced Queue Position
- Advanced Queue position allows for entry to the SIS stage and is attained only after defined Progression Milestones are met
- Limited project modifications can be made without loss of queue position
- Queue position can only be transferred to another entity if the Generating Facility is acquired

Nova Scotia POWER An Emera Company

GIP – Transmission Project Workflow

- Interconnection Request
- Scoping Meeting
- Feasibility Study
- Progression Milestones met by IC
- System Impact Study
- Facilities Study
- E&P Agreement (Optional)
- Optional Studies
- Generator Interconnection and Operating Agreement (GIA)

GIP – Progression Milestones

- Provision of:
  - Detailed stability model for the generator(s)
  - Completed Attachment A to Appendix 1
  - Confirmation of the Point of Interconnection
  - One-line diagram with rating and impedance information
  - Confirmation of generation MW output
  - Re-validation of Site Control
  - And…

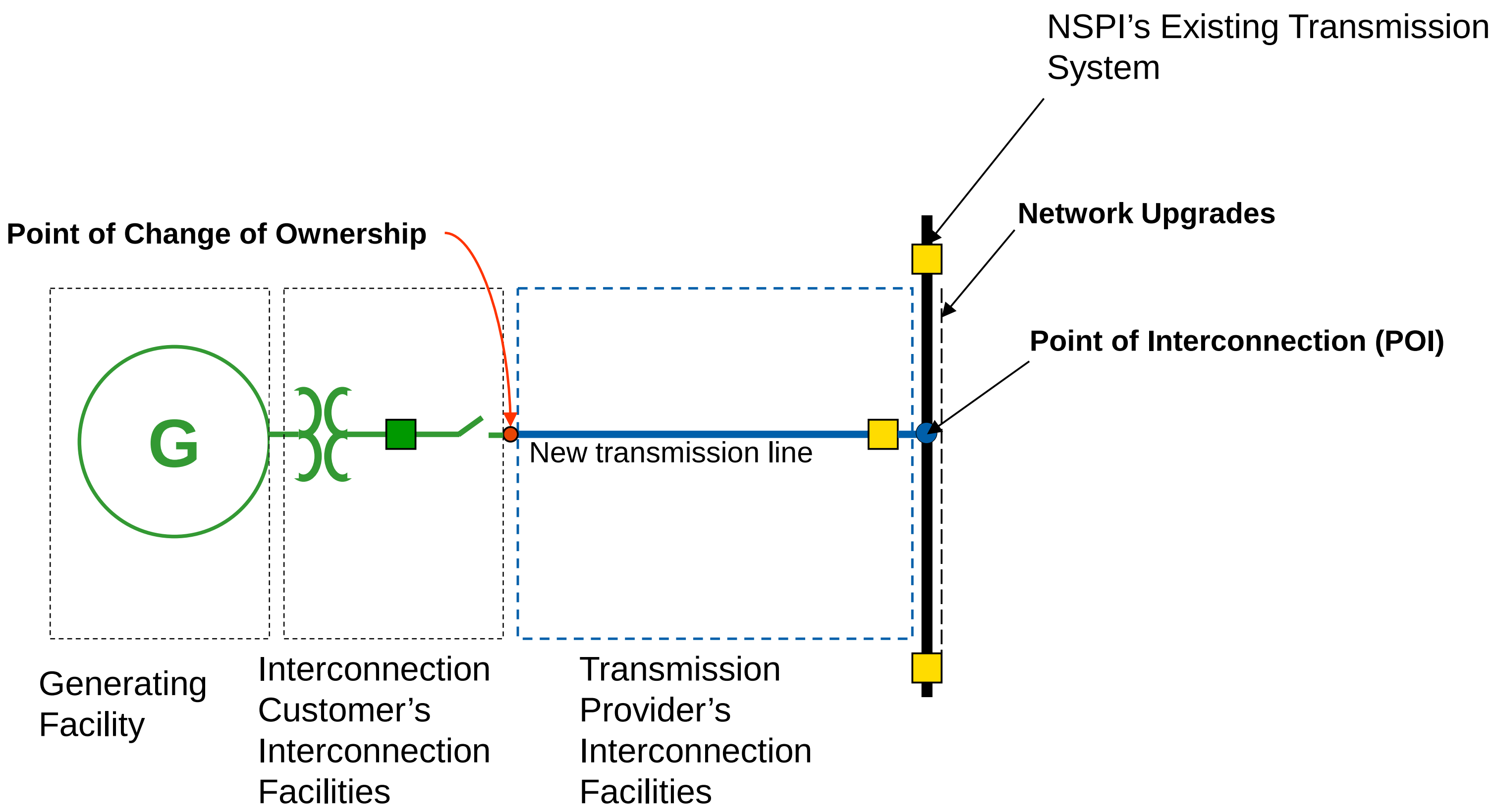
Nova Scotia POWER An Emera Company

GIP – Progression Milestones

- Provision of:
  - Any one of the following:
    - Executed contract for sale of energy (>50% capacity)
    - Long-term transmission service reservation (1yr > 50% capacity)
    - Approval by the NSUARB for the Generating Facility expenditures
    - The project's energy/capacity has been identified as being required to meet demand, reliability or Renewable Energy Standard requirements by a load serving entity.

Nova Scotia POWER
An Emera Company

Interconnection Facilities Ownership



Cost Responsibilities under the GIP

- Generating Facility
  - Built, owned and funded by the Customer
- Interconnection Customer Interconnection Facilities:
  - (ICIF) Built, owned and funded by the Customer
- Transmission Provider Interconnection Facilities:
  - (TPIF) Built & owned by NS Power, but funded by the customer
- Network Upgrades (NU):
  - Built & owned by NS Power, but funded by the Customer with refund mechanism (for transmission network upgrades only) in the Generator Interconnection Agreement

Nova Scotia POWER An Emera Company

Generator Interconnections

Distribution Connected (Below 69 kV – typically 25kV and below)		Transmission Connected (69 kV and above)
Under 100 kW Class 1	Over 100 kW Class 2 Distribution Interconnection Procedures (DGIP)	Generator Interconnection Procedures (GIP)

Nova Scotia POWER
An Emera Company

Distribution Generator Interconnection Procedures

- The DGIP accommodates Generator access to the NS Power distribution system for sale of energy to NS Power via PPA, COMFIT, or net metering
- It does not accommodate direct to retail sales of energy or capacity from Generators
- It does not include use of the transmission system or permit transmission system impacts
- Total generation is typically limited to minimum distribution substation load

Nova Scotia POWER An Emera Company

DGIP – Distribution Project Workflow

- Interconnection Request
- Preliminary Assessment
- Progression Milestones Met by IC
- Combined Distribution System Impact Study / Facilities Study
- Optional Studies
- Standard Small Generator Interconnection and Operating Agreement (SSGIA)

DGIP – Progression Milestones

- Provision of:
  - $10,000 Study deposit
  - Generator Data
  - Completed Attachment A to Appendix 1
  - Confirmation of the Point of Interconnection
  - One-line diagram with rating and impedance information
  - Confirmation of generation MW output
  - And…

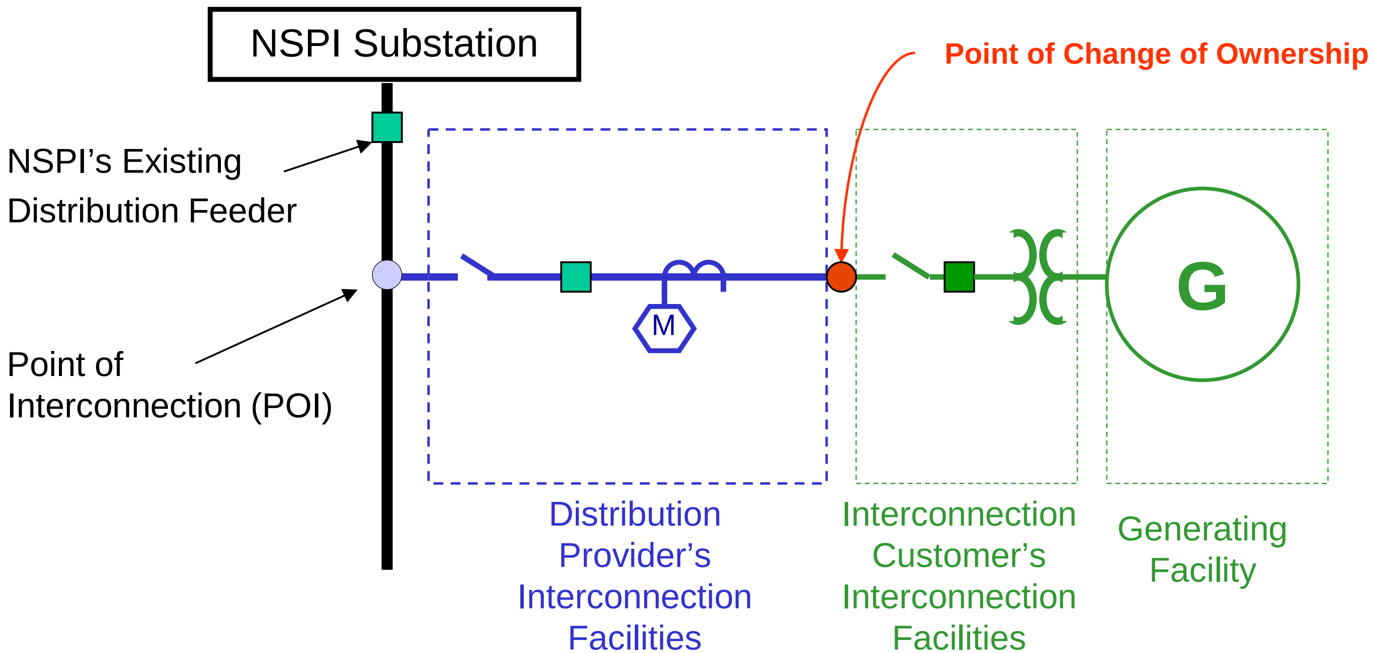
Nova Scotia POWER
An Emera Company

DGIP – Progression Milestones

- Provision of:
  - Any one of the following:
    - Executed contract for sale of energy (>50% capacity)
    - Approval by the NSUARB for the Generating Facility expenditures
    - COMFIT Approval
    - Net Metering Approval per NS Power Reg. 3.6
    - The project's energy/capacity has been identified as being required to meet demand, reliability or Renewable Energy Standard requirements by a load serving entity.

Nova Scotia POWER An Emera Company

DGIP Generator Interconnection Facilities



Cost Responsibilities under the DGIP

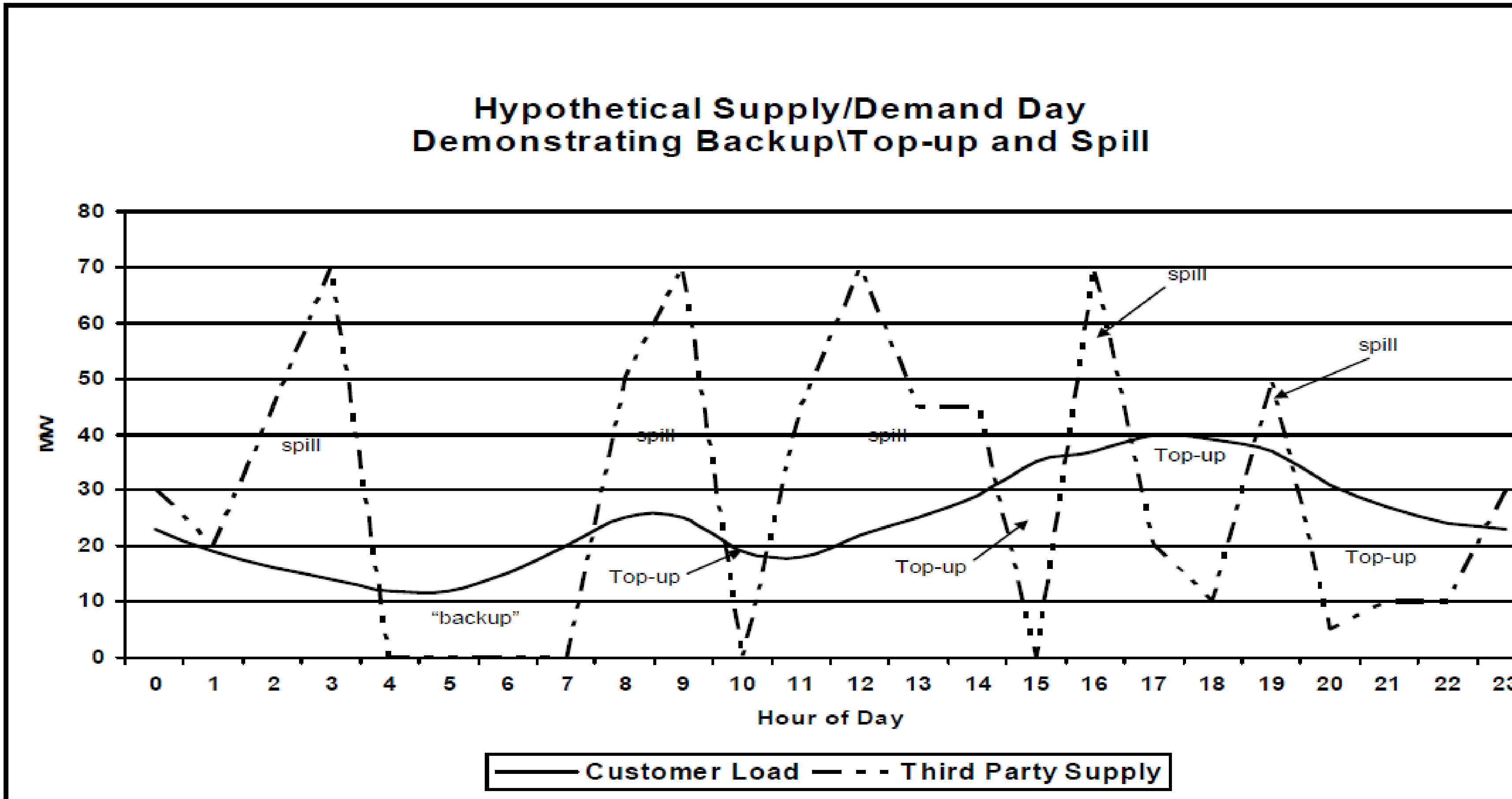
- Generating Facility
  - Built, owned and funded by the Customer
- Interconnection Customer Interconnection Facilities:
  - (ICIF) Built, owned and funded by the Customer
- Distribution Provider Interconnection Facilities:
  - (DPIF) Built & owned by NS Power, but funded by the customer
- Network Upgrades (NU):
  - Built & owned by NS Power, but funded by the Customer

Nova Scotia POWER
An Emera Company

THURSDAY, FEBRUARY 12, 2015

Backup / Top-up Service Tariff

Back Up/Top Up & Spill



BUTUS - Availability

Presently available to Wholesale Customers per Section 2(b) of the Electricity Act:

BUTUS - Design

Designed for customers supplied via the transmission System at voltages of 69kV and higher with metering at transmission voltages

For customers metered at the low side of the transformer, or at a distribution voltage level, meter readings are increased by 1.75% for each transformation between the meter and the transmission voltage.

Charges under BUTUS do not reflect transmission service costs. Customers taking service under this tariff must also take service under OATT.

Nova Scotia POWER
An Emera Company

BUTUS - Charges

BUTUS charges have three components:

- **Administration Charge**: based on # of subscribed customers
- **Demand Charge**: Based on kW of Billing Demand measured on average hourly basis
- **Energy Charge**: Average annual marginal energy cost as approved for GRLF rate

Nova Scotia POWER
An Emera Company

BUTUS - Requirements

- Applicable to the scheduled backup\top-up load of participating customers
  - Written notice required by Jan 31 for following year
  - Minimum 12 month annual renewal term
  - Annual renewal by Jan 31
  - Adequate metering per GIP/GIA
  - Transmission Service also required under OATT
  - Operating agreement; separate service agreement

Applications

Customer is required to provide SO with day ahead balanced schedule of load and supply (by hour), including BUTUS requirements. For example:

- 40 MW of load at 10 AM
  - 30 MW from Supplier X; 10 MW Top-up from NS Power
- 27 MW of load at 11 AM
  - 27 MW from Supplier X; 3 MW of Spill to NS Power

Nova Scotia POWER An Emera Company

Spill - Requirements

- Applicable to the scheduled Spill energy of independent non-dispatchable electric generators serving customers taking service under BUTUS:
  - Adequate metering per GIP/GIA
  - Suppliers must meet all conditions set forth in the GIP/GIA
  - May require a separate service agreement

Nova Scotia POWER
An Emera Company

Spill - Charges

Spill charges have two components:

- **Administration Charge**: based on # of suppliers
- **Energy Credit**: Compensated at the Company's forecast average annual marginal energy costs as approved for use with the GRLF rate.

(Minimum Monthly Charge: Shall be the administration charge)

Nova Scotia POWER An Emera Company

Questions

?

Nova Scotia POWER An Emera Company

Nova Scotia Power
Renewable to Retail Project
Design basis development

Robert Cary & Associates Inc.

March, 2015

Structure of presentation

- Part 1: Purpose of presentation
- Part 2: Licencing and market participation
- Part 3: Customer-facing design
  - *Disaggregated tariff option*
  - *Billing & collection responsibility*
  - *Full / partial service and related issues*
  - *Metering*
  - *Billing & collection process*
  - *Customer service change requests*
- Part 4: Tariffs
  - *Tariff framework*
  - *Tariff design*
- Part 5: ECR issues
- Part 6: Data points
- Part 7: Consultation Questions

Purpose of presentation

- To identify the present status of the RtR market design, and set out the basis for decisions made to date including in response to stakeholder feedback.
- To identify issues under consideration in the next stages of design and note options that may be under consideration.
- Indicate some preliminary data points for certain of the charges, using existing public information
- Seek ongoing stakeholder feedback.

Licencing and market participation

- NS Power assumptions include:
  - *The UARB will licence qualified retail suppliers (as LRS) and will establish the regulations etc. under which LRSs will interact with customers; and*
  - *The UARB will consider compliance obligations including:*
    - *Each LRS must in each year secure the injection into the grid of electricity from certified low impact renewable generators at least equal to the electricity sold plus allowance for losses; and*
    - *To the extent that a generator or LRS sells the renewable attributes associated with such electricity, that electricity shall cease to qualify to meet this compliance requirement.*
- Market Participation by LRS - options under consideration:
  - *RtR participation agreement or LRS-specific T&Cs document;*
    - *Incorporating mandatory tariff participation and overall settlement framework including metering information access and service changes.*
  - *Modified wholesale market participation agreement;*
    - *With the above specifics included in modified market rules.*

Customer facing design #1

- Disaggregated tariff option
  - *There was a clear but not universal stakeholder preference for this option;*
  - *NS Power is developing the RtR market design on this basis.*
- We identify two groups of tariffs to be developed and implemented:
  - *Aggregated (charged / credited on the basis of aggregate quantities):*
    - *Generation backup;*
    - *Top-up;*
    - *Spill;*
    - *ECR if charged as an ongoing retail access adjustment (capacity and energy); and*
    - *OATT network service.*
  - *Customer-specific charges / credits derived from individual customer metering:*
    - *Distribution service (including retail service);*
    - *DSM cost recovery;*
    - *FAM exit fee or credit and ECR for capacity and energy if charged as exit fee;*
    - *Interruptibility credit (as existing for large interruptible customers); and*
    - *Special service fees (eg special meter reads) if applicable.*

Customer facing design #2

- LRS consolidated billing and collection:
  - *There was a clear stakeholder preference for this option; and*
  - *Appears workable subject to the participation agreement / market rules providing appropriate cash flow and payment security provisions as between NS Power and the LRS.*

Customer facing design #3

- Partial service:
  - *Note that any customer with multiple accounts may select RtR service per account; each account under 2,000 kVa must be 100% RtR or NS Power service:*
    - *This is not categorised as partial service.*
  - *Some stakeholders indicated a preference for a partial service option, none opposed.*
  - *NS Power is examining the potential for implementing the following framework:*
    - *Eligibility limited to customers in classes > 2,000 kVA;*
    - *No change to any interruptibility provisions as a result of RtR service;*
    - *Predetermined and constant % split of kWh load in each hour of a calendar year, peak demand, etc; and*
    - *Still reviewing impact on customer rate class as a result of partial service.*

Customer facing design #4

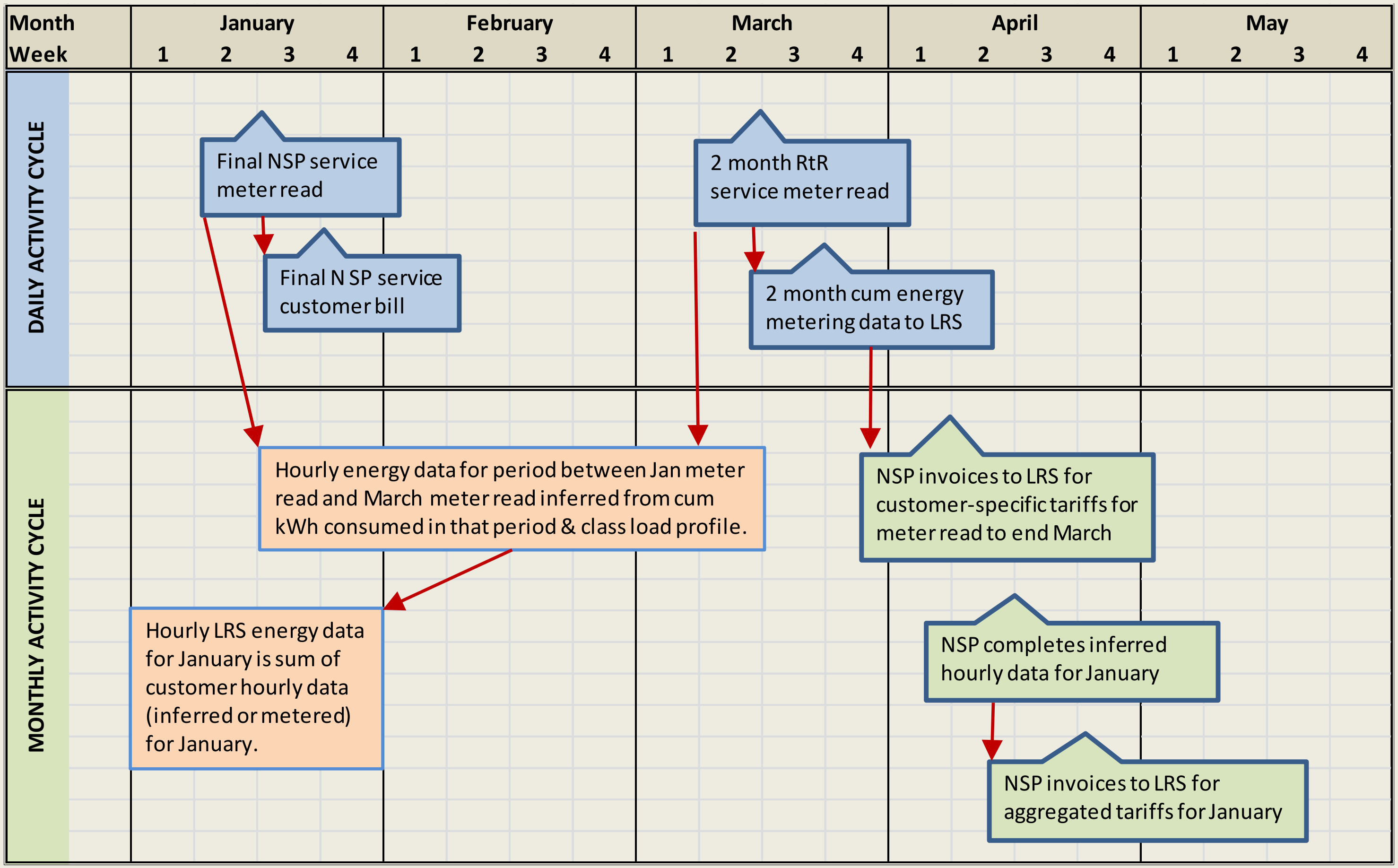
- Metering
  - *General stakeholder acceptance for continued NS Power ownership and meter reading.*
    - *One request for an option of LRS metering (but excluded for complexity).*
  - *General stakeholder acceptance for continued use of existing meters as required for each customer class, including cumulative energy meters for residential & small general classes.*
  - *This represents a least initial cost option for market commencement, but at the expense of some complexity of settlement calculations (see next slide):*
    - *Ongoing work to consider other options (e.g. monthly meter reading, interval metering).*
  - *NS Power has identified some further requirements:*
    - *Seasonal meter reading cycles cannot be supported; the longest permitted meter reading and billing cycle would be 2 months;*
    - *All partial service customers will require hourly interval metering with remote polling capability (which should generally be in place today for such customers); and*
    - *NS Power considering whether the requirement for interval metering should also include other customers below 2,000 kVA class.*
  - *Potential evolution with RtR growth and general metering developments.*

Customer facing design #5

- Certain tariff settlements require hourly data, including:
  - *OATT (for peak demand determination); and*
  - *Top-up and spill / energy imbalance.*
- For customers with cumulative energy metering, these hourly data will require to be inferred by NS Power. The process as presently envisaged (with indicative timing for settlement for January) is:
  - *Raw meter reading data will be processed by NS Power according to meter reading and billing cycles and passed to the LRS;*
  - *NS Power will bill to the LRS for charges based directly on metering data ;*
  - *NS Power will use standard customer class (or sub-class) load profiles to infer hourly data for each 2-month reading of cumulative energy meters; and*
  - *NS Power will thus require all 2-month cumulative energy meter readings to the end of March in order to determine the aggregate hourly LRS load for January, and thus to determine January peak aggregate LRS demand (for OATT) and hourly quantities for each of top-up and spill.*

Customer facing design #5a

- Illustration of potential billing cycle per previous slide



Customer facing design #6

- Billing & collection processes
  - *Detail to be developed including recognition of:*
    - *Split between aggregated charges and customer-specific charges;*
    - *Timing lags arising under some tariffs from the 2-monthly cumulative energy metering cycle, compounded by the need to infer hourly load data;*
    - *Potential offsets (eg between top-up charge and spill credit); and*
    - *Management of cash flow and credit exposure between NS Power and each LRS.*

- Service change requests
  - *NS Power will be developing administrative processes recognising, inter alia:*
    - *Administrative notice requirements;*
    - *Minimum normal contract term and any default renewal /end-of-term provisions;*
    - *Linkage to meter reading dates;*
    - *Life event provisions;*
    - *Final NS Power billing collection; and*
    - *Security deposit requirements applicable to returning customers.*

Tariff framework #1

- Tariffs are non-discretionary
  - *Each LRS will be a customer under all of the tariffs identified as applicable to the RtR market:*
    - *The LRS cannot opt out of applicable tariffs (eg backup, ECR);*
    - *The spill tariff is currently configured as a generator tariff, separate from top-up. Settlement and cash flow may be simplified if the LRS becomes the spill tariff customer;*
    - *This is under consideration; and*
    - *See slide below on top-up & spill tariff design.*

Tariff framework #2

- Rates set in advance and may contain seasonal and/or time-based rates:
  - *Rates will be set on a forward test year basis such that, over the test year, they recover the costs associated with providing the applicable services, including embedded costs otherwise stranded by the provision of those services, thus:*
    - *Providing predictability to the LRS within each year; and*
    - *Minimising burden of ex-post hourly calculations.*
- NS Power would expect the discretion to apply for rate adjustments on the same cycle as for full service rates.

Tariff design #1: quantum of RtR backup required

- RtR backup tariff concept under consideration
  - *The concept was introduced in my December presentation slides 8 – 11.*
  - *Each LRS must self-provide or procure under the backup tariff its share of the system net requirement for dependable firm capacity:*
    - *The system gross requirement is 1.20 x the planned coincident peak load;*
    - *The system net requirement is reduced somewhat from this by the charge out of some capacity through the OATT charges for capacity-based ancillary services;*
    - *The LRS share would notionally be based on its share of the annual coincident peak:*
      - This concept is relatively straightforward to implement under a steady state of LRS market share, e.g. by adopting the demand ratchet embedded in the existing large industrial tariff;
      - More challenging to implement when customers are migrating; and
      - Design must provide reasonable allocation of responsibility, and avoid perverse incentives to time service changes.

Tariff design #2: fixed cost classification and recovery

- Rate basis options under consideration for backup and ECR
  - *Embedded cost – initial classification as capacity*
    - *This approach attributes most fixed cost to capacity, so results in highest capacity rates, both for backup and for capacity ECR*
  - *Embedded cost – final classification as demand / energy charge*
    - *Basis of Cost of Service filings in support of existing full service rates*
    - *A significant portion of fixed cost is classified for recovery on the basis of energy consumption*
    - *A large part of the fixed cost stranding would result from the foregone revenue linked to energy consumption (ref my Dec presentation slide 11 bullet 2.2)*
    - *This could lead to a significant ECR linked to RtR energy consumption*
  - *Marginal capacity cost / cost of new entry (proxy unit)*
    - *As presently utilised in the backup demand charge tariff calculation*
    - *To the extent that this differs from embedded cost approaches, it will result in different levels of stranding for ECR*
  - *It will be important to adopt a tariff design that recovers costs appropriately for a range of RtR generation technologies having potentially different capacity / energy characteristics.*

Tariff design #3: RtR top-up and spill #1

- Linkages and tariff customers:
  - *Present linkages:*
    - *Top-up energy is linked to backup capacity and the combined service is provided to wholesale load transmission customers; and*
    - *Spill is a separate tariff and the service is provided to a generator.*
  - *Proposed linkages under consideration:*
    - *The LRS would be the customer under a backup capacity tariff:*
      - The generator would allocate the benefit of its <u>capacity</u> to the LRS in order that the LRS could use it as self-supplied capacity to mitigate its backup capacity obligation.
    - *The LRS would be the customer under a top-up and spill tariff:*
      - The generator would allocate its <u>energy production</u> to the LRS;
      - The LRS would use energy to supply its RtR customers (and cover associated losses);
      - The LRS would sell additional energy as spill under the spill tariff;
      - Payment between the LRS and the generator could thus be independent of the hourly RtR load;
      - Top-up and spill cash flow between the LRS and NS Power could be offset; and
      - The LRS has single point responsibility to NS Power to maintain any required annual balance between top-up and spill quantities.
  - *Top-up and spill are separate from OATT imbalance charges:*
    - *Tariffs will provide delineation between the two.*

Tariff design #4: RtR top-up and spill #2

- Rates
  - *Predetermined rates:*
    - *It is expected that rates will be predetermined for each year.*
    - *The alternative, hourly ex post determination, would be unduly complex and costly:*
      - As noted in slide 13 the extra precision would not affect non-RtR customers;
      - Stakeholders have indicated a preference for certainty; and
      - The cost of administering hourly ex-post marginal cost determination would need to be recovered through a rate payable by the LRS.
  - *Basis for rates:*
    - *The marginal system cost varies in a number of ways:*
      - Somewhat predictable seasonal load patterns;
      - Somewhat predictable daily / hourly load patterns; and
      - Driven by variable generation (for which the effects can be greater than predictable load patterns).
    - *For constant RtR generation, there will be a predictable excess (spill) during low load periods and shortfall (top-up) during high load periods;*
    - *For wind RtR generation, there would be a high correlation of spill with high levels of other wind generation, and of top-up with low levels of other wind generation;*
    - *The rates will need to reflect these differences.*

Tariff design #5: OATT

- General
  - *The OATT will be subject to a general review.*
  - *It is expected that the network service charge determinant for aggregated RtR load will not be netted down for any distribution-embedded generation:*
    - *All backup and top-up services utilise the transmission network for delivery to these RtR customers, irrespective of RtR generator location, so the transmission system requirements are not reduced by distribution-embedded generation.*
  - *It will be necessary to consider the implications of the annual demand ratchets presently implicit in the large customer class full service rates in setting charge determinants and rates.*
  - *Other issues will be brought forward as identified.*

Tariff design #6: distribution and associated services

- Distribution service:
  - *This will be a customer-specific tariff based and billed to the LRS on the basis of individual customer meter-reads and class rates;*
  - *Other issues will be brought forward as identified.*
- Retail service:
  - *Retail service cost is a separate cost class in the COS filing, and represents costs which NS Power will generally continue to bear in respect of RtR customers;*
  - *This may be included in the distribution service tariff or may be separate.*
- DSM:
  - *The same as the DSM charge applicable to NS Power full service customers.*
- Interruptibility:
  - *If RtR service is available to interruptible customers, consideration must be given to how processes, credits, and penalties associated with interruptibility would be administered if they are not NS Power 's end customer.*
- Special Services:
  - *These will be developed if and as required.*

ECR issues

- The quantum of embedded cost to be recovered under an ECR mechanism
  - *Will depend on the amounts recovered through the backup tariff;*
  - *Should be the same whether the ECR mechanism is:*
    - *A capacity based retail access adjustment;*
    - *An energy based retail access adjustment; or*
    - *An exit fee associated with individual customer exit:*
      - This would provide for a present-value equivalent lump sum;
      - Could be based on customer class and historic consumption; and
      - Could reflect energy, demand or a combination.
- Retail Access Adjustment or Exit Fee: under consideration
  - *Natural Forces expressed preference for exit fee with phased payment;*
  - *No other preferences stated: both options remain under consideration;*
  - *Retail access adjustment assessed on the aggregate of each LRS load appears to avoid contention over potential duration of RtR supply, duration of stranding, and long term projections; it also mitigates immediate cash flow. This may drive a preference for a Retail Access Adjustment option.*
  - *FAM exit fee / credit would probably be lump sum exit fee / credit.*

Pricing data points

Pricing data points: 2014 COS Exhibit 6.1

Whole system totals	$ million	c/kWh 9,116
Generation		
Fuel & purchased power	448	4.91
Fixed & other cost	482	5.29
Credit ancillary services (1)	(24)	(0.26)
subtotal generation	906	9.94
Transmission		
Network service	107	1.18
Ancillary services	24	0.26
subtotal transmission	132	1.44
Distribution & retail		
Distribution	188	2.06
Retail	52	0.57
subtotal dist & retail	240	2.63
Total	1,277	14.01

Note (1): It is assumed that 5% of fixed generation cost is attributed to operating reserves etc

Consultation questions

- Customer facing design, slides 5 to 11
  - *Based on the design development as indicated in this presentation, do stakeholders have:*
    - *Concerns previously expressed that they consider inadequately addressed?*
    - *New concerns arising from the progressing development of the design?*
- Tariff framework, slides 4 (bullet 2) 12 & 13
  - *Are there any aspects of this framework that present insurmountable concerns to potential participants, and if so how can these be addressed within the requirements of the program?*
- Tariff design, slides 14 to 19
  - *Recognising that all tariffs and participation agreements can come into effect only following UARB approval, do stakeholders have particular issues or preferences to be considered in development of tariff applications or standard agreements etc?*
- ECR, slide 20
  - *Any additional stakeholder comments on the preferred form (RAA or exit fee)?*

Nova Scotia POWER
An Emera Company

MARCH 2, 2015

Stakeholder Session #4

Renewable to Retail Market Opening
Renewable to Retail Work Plan

RtR Work Plan Elements:

Working backwards from our September 1st NSUARB filing date, we are targeting to have all market materials substantially complete by early July.

- NSP Preparation and drafting of market documentation
  - Present to late May
- Stakeholder review process of proposed market documentation
  - Starting Mid-April to early July.

- *We have a lot of detailed work ahead of us.*

Nova Scotia POWER An Emera Company

Process in more detail:

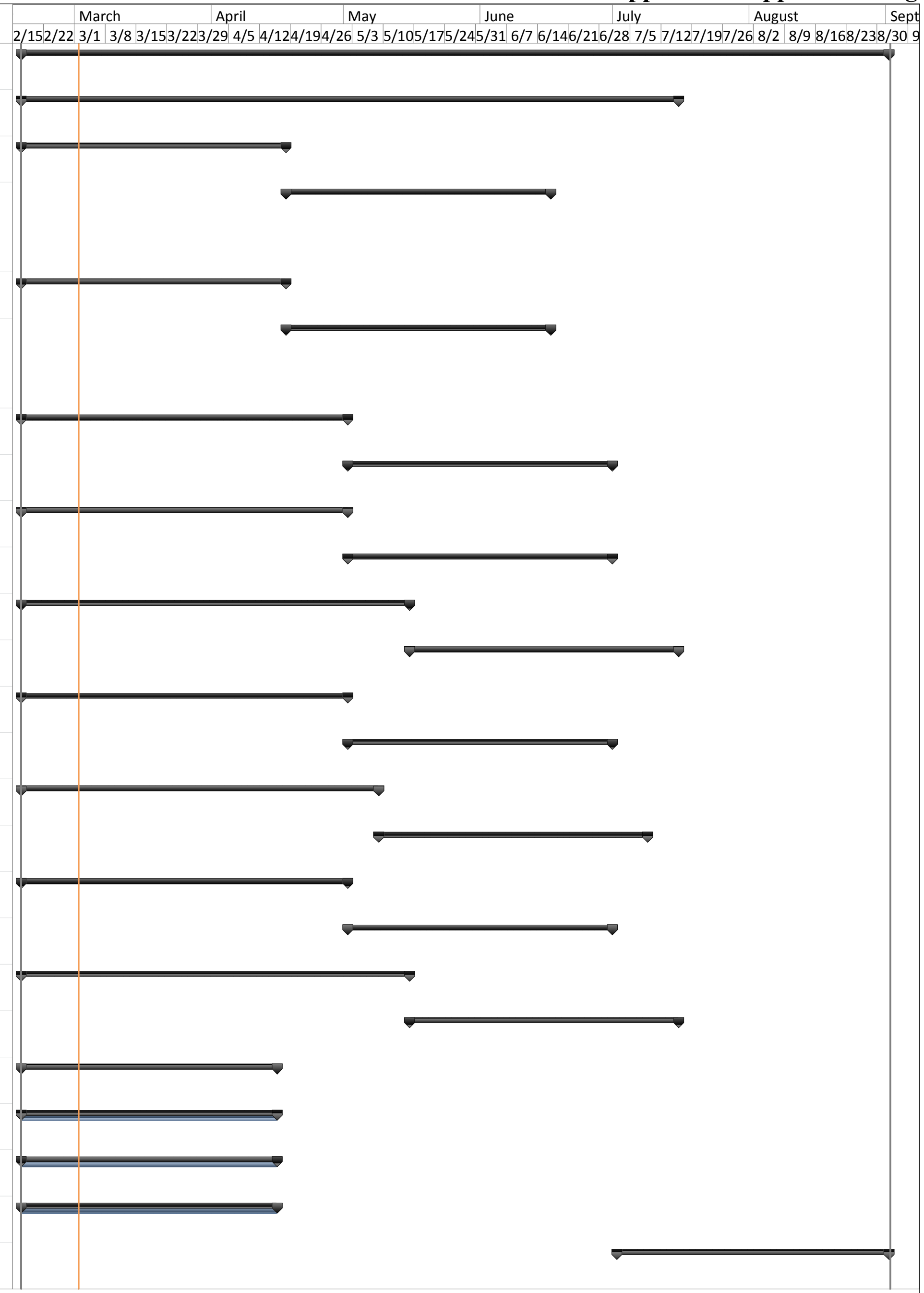
1. NSP drafts RtR Market documentation/strawman.
2. NSP submits RtR market documentation/strawman for Stakeholder review.
3. Stakeholders review documentation.
4. Stakeholders submit Data Requests.
5. NSP replies to Data Requests.
6. Stakeholders review NSP DR responses.
7. Stakeholders provide written submissions.
8. NSP finalizes RtR market documentation/strawman.

(Additional Stakeholder sessions arranged as required.)

Schedule

PLEASE SEE ATTACHED PDF DOCUMENT
FOR THE SUMMARY SCHEDULE

ID	Task Name	Duration	Start	Finish
1	**Renewable to Retail Work Plan**	**135.94 days**	**Feb 17 '15**	**Sep 1 '15**
2	**Tariff Elements**	**103 days**	**Feb 17 '15**	**Jul 15 '15**
3	**Develop Distribution Tariff Pricing**	**42 days**	**Feb 17 '15**	**Apr 17 '15**
9	**Stakeholder Distribution Tariff Pricing Review/DR process**	**41 days**	**Apr 17 '15**	**Jun 16 '15**
16	**Develop Distribution Tariff Documentation**	**42 days**	**Feb 17 '15**	**Apr 17 '15**
21	**Stakeholder Distribution Tariff Documentation Review/DR process**	**41 days**	**Apr 17 '15**	**Jun 16 '15**
28	**Amend Back Up/TopUp Tariffs**	**52 days**	**Feb 17 '15**	**May 1 '15**
33	**Stakeholder Back/Up Top/Up Review/DR process**	**41 days**	**May 1 '15**	**Jun 30 '15**
40	**Amend Spill Tariff**	**52 days**	**Feb 17 '15**	**May 1 '15**
45	**Stakeholder Spill Tariff Review/DR process**	**41 days**	**May 1 '15**	**Jun 30 '15**
52	**Develop ECR**	**62 days**	**Feb 17 '15**	**May 15 '15**
58	**Stakeholder ECR Strawman Review/DR process**	**41 days**	**May 15 '15**	**Jul 15 '15**
65	**Develop/Amend OATT**	**52 days**	**Feb 17 '15**	**May 1 '15**
70	**Stakeholder OATT Review/DR process**	**41 days**	**May 1 '15**	**Jun 30 '15**
77	**Amend GIP/DGIP**	**57 days**	**Feb 17 '15**	**May 8 '15**
84	**Stakeholder GIP/DGIP Review/DR process**	**41 days**	**May 8 '15**	**Jul 8 '15**
91	**Develop/Amend Market Rules**	**52 days**	**Feb 17 '15**	**May 1 '15**
98	**Stakeholder Market Rules Review/DR process**	**41 days**	**May 1 '15**	**Jun 30 '15**
107	**Develop/Amend Market Procedures**	**62 days**	**Feb 17 '15**	**May 15 '15**
112	**Stakeholder Market Procedures Review/DR process**	**41 days**	**May 15 '15**	**Jul 15 '15**
119	**Other Items**	**40 days**	**Feb 17 '15**	**Apr 15 '15**
120	**Billing**	**40 days**	**Feb 17 '15**	**Apr 15 '15**
124	**Metering**	**40 days**	**Feb 17 '15**	**Apr 15 '15**
126	**Partial Service**	**40 days**	**Feb 17 '15**	**Apr 15 '15**
128	**UARB Application**	**42.94 days**	**Jul 2 '15**	**Sep 1 '15**



From: Aaron Long <aaron.long@minasenergy.com>
Sent: Monday, March 16, 2015 2:29 PM
To: LEFLER, LINDA
Cc: Aaron Akitt; Adam Baggs; Antoine Gamarra (agamarra@wrassoc.com); Auley Carey; Austen Hughes; Bill Mahody; Brady Ryall (bryall@energyconsultants.ca); Bruce Outhouse; Bruce Thompson; Chris Peters; Christine Kavanagh; Craig Whitman; CURRY, BRIAN; Dana Morin; Daniel Roscoe; David MacDougall; David McLennan; David Regan; Debbi Bolton; Don Regan; Duncan Elliott; Ellen Burke; ELLIS, BILL; Eva Schmidt; FERGUSON, ERIC; Geneva Looker (glooker@wrassoc.com); George LeBlanc; Holly Bond; James MacDuff; Jocelyn Fraser; John Athas; John Brereton; John Merrick; John Woods; Keith Towse; LANDRIGAN, DAVID; Leona Clements; Leonard van Zutphen; Luciano Lisi; Maggie Stewart; Mark Drazen; Mel Whalen; Melissa Whitten; Michael Morris; MYATT, LANA; Nancy Rondeaux; Nancy Rubin; Nelson Blackburn; Paul Lewis; Paul Pynn; Peggy Merrill; Peter Archibald; Peter Craig; Richard Melanson; Rob Apold; Rob Cary; Rochelle Owen; RODENHISER, DAVID; Ron Seftel; Sandy Durling; Sandy White; Scott McCoombs; Stan Mason; Stephen McGrath; Stephen Thomas; Steve Pronko; SUTHERLAND, LAURA; Whitfield Russell (whtfldrussell@aol.com)
Subject: Re: M06321 - Renewable to Retail Stakeholders - Please respond by March 16, 2015

Linda,
Minas has no further points beyond what was expressed verbally during the previous consultation session.
Kind regards,

Aaron Long, P.Eng., M.Sc.
Director of Business Development
Minas Energy
902-497-1447 (c)
www.minasenergy.com

On Tue, Mar 3, 2015 at 12:19 PM, LEFLER, LINDA <Linda.Lefler@nspower.ca> wrote:
Hello all,
The NS Power materials from yesterday's meeting (and our February 12 information session) are on the NS Power website. Your feedback on the project materials is requested by Monday, March 16, 2015, to me, and preferably copied to this participants list. Once the feedback is received we'll also place it on that site for future reference.
Thank you.
Linda Lefler

Canada Anti-Spam Law Notice – To stop receiving commercial electronic messages from us, please forward this email to unsubscribe@nspower.ca with the word "unsubscribe" in the subject line. | Nova Scotia Power | 1223 Lower Water Street, Halifax NS B3J 3S8 | www.nspower.ca

Confidentiality Notice - The email communication is considered confidential and is intended only for the recipient(s). If you received this email in error, please contact the sender and delete the email. Unauthorized disclosure or copying of this email is prohibited.

Attachment Limits - Emera will not accept email larger than 20MB or emails containing high risk attachments like ZIP, EXE or others that could contain viruses. If you have a business need to send such an email, please contact the recipient for instructions.

MCINNES COOPER
LAWYERS | AVOCATS

David S. MacDougall
Direct +1 (902) 444 8561
david.macdougall@mcinnescooper.com

Purdy's Wharf Tower II
1300-1969 Upper Water Street
PO Box 730
Halifax NS
Canada B3J 2V1
Tel +1 (902) 425 6500 | Fax +1 (902) 425 6350

Our File: 100384
March 16, 2015

Ms. Linda Lefler, P. Eng.
Regulatory Project Manager
Nova Scotia Power
P.O. Box 910
Halifax, NS B3J 2W5

Dear Ms. Lefler:

Re: Renewable to Retail Process – Feedback on March 2, 2015 Technical Conference

On February 27, 2014, Nova Scotia Power Inc. ("NS Power") circulated a presentation for discussion at the technical conference that was held with stakeholders on March 2, 2015. Please accept the following feedback on behalf of Port Hawkesbury Paper LP ("PHP") following the technical conference.

In its January 9, 2015 letter, PHP provided comments on some of the points regarding embedded cost recovery ("ECR") that were raised in Robert Cary's White Paper. PHP notes that there was limited discussion on the specific issues related to the development and calculation of the potential costs to be included as part of an ECR mechanism in the March 2, 2015 technical conference. PHP expects that the issues involved in determining the embedded costs to be recovered under an ECR mechanism, and the specifics of such a mechanism, will be the subject of more detailed examination and discussion as this process unfolds.

In its January 9, 2015 letter, PHP also emphasized the importance of ensuring that large industrial customers would have the option of taking partial service under the Renewable to Retail framework. PHP is pleased that NS Power is now examining the implementation of a framework that would allow partial service for customers in classes greater than 2,000 kVA. PHP looks forward to reviewing the details of the proposed framework for partial service and may have further comments once these details are available.

Thank you for the opportunity to submit these comments.

Yours truly,

David MacDougall

cc: Interested Parties

(19742102)

March 16, 2015

Nova Scotia Power Inc.
1223 Lower Water St.
Halifax, Nova Scotia
B3J 2W5

RE: M0614 – Comments Regarding March 2, 2015 Technical Conference

Scotian WindFields Inc. welcomes the opportunity to participate in the Renewable to Retail Market Opening process and submits the below comments and suggestions.

These comments are regarding the March 2, 2015 Technical Conference and supporting Renewable to Retail Work plan, Project Design Basis Development presentation and other documentation. Specifically, we have prepared feedback regarding:

- Metering
- Backup and Spill Procurement
- Timing and Frequency of Rate Setting
- Distribution and Transmission System Distinctions

Should you require any clarification or further details on and of the points included in this response, please do not hesitate to contact Scotian WindFields Inc. directly.

Thank you for your consideration of these comments and we look forward to further discussion and analysis.

Sincerely,

Daniel Roscoe, P.Eng.
Chief Operating Officer
Scotian WindFields Inc.

Scotian WindFields
Community Owned. Naturally.

1) Metering
On page 9 of the 'Nova Scotia Power Renewable to Retail Project Design basis development' presentation prepared by Robert Cary, it is outlined that standard customer class (or sub class) load profiles will be used to infer hourly data for each 2-month reading of *cumulative* energy meters.

Scotian WindFields Inc. believes that a number of forecasting and accuracy challenges are presented with this use of these predetermined load profiles. We request that Renewable to Retail customers be presented with an option for installation of a new *meter with hourly energy reading capability*. This meter will still be owned and read by Nova Scotia Power Inc. on a bi-monthly basis, but will provide more accurate load profiles for Renewable to Retail Customers.

2) Backup and Spill Procurement.
On page 12 of the 'Nova Scotia Power Renewable to Retail Project Design basis development' presentation prepared by Robert Cary, it is outlined that each Licensed Retail Supplier cannot 'opt out' of applicable tariffs, including backup and spill.

Scotian WindFields Inc. would like to request that it be considered that Licensed Retail Suppliers be able to source independent contracts for backup and spill services, provided the services comply with all applicable regulations.

3) Timing and frequency of Rate Setting
On page 12 of the 'Nova Scotia Power Renewable to Retail Project Design basis development' presentation prepared by Robert Cary, it is outlined that rates be set in advance and may contain seasonal and/or time-based rates, set on a forward test year basis.

In general, Scotian WindFields Inc. agrees with this approach. We would further suggest that hourly rate schedules on a per weekday/weekend be considered on a monthly basis.

4) Distribution and Transmission System Distinctions
On page 18 of the 'Nova Scotia Power Renewable to Retail Project Design basis development' presentation prepared by Robert Cary, it is outlined that it is expected that the network service charge determinant for the aggregated Renewable to Retail load will not be netted down for distribution-embedded generation, under the reasoning that all backup and top-up services utilize the transmission network, irrespective of generator location.

Scotian WindFields Inc. would request that if a LRS-to-customer system were to be designed with 100% of the generation and consumption taking place on a single distribution network, that the transmission-specific services not be needed. We agree that clarity is needed regarding which rates within the OATT are embedded and which will require an additional charge.

108F Trider Cres, Dartmouth, NS B3B-1R6|
info@scotianwindfields.ca | www.scotianwindfields.ca

Board Electricity Retailers Regulations (Nova Scotia) enacted under the Electricity Act

Prepared by Energy Consultants International, Inc.
Brady Ryall, P.Eng.

July 15, 2015

1 These Regulations may be cited as the *Board Electricity Retailers Regulations (Nova Scotia).*

Definitions

2

2(1) In these Regulations, unless the context indicates otherwise, words and expressions have the same meaning as in the *Electricity Act* and the *Renewable Electricity Regulations (Nova Scotia)* enacted under s. 5 of the Act.

2(2) In these Regulations

"Account Holder", in relation to a Premises, means the person listed on the account of NS Power for the delivery of electricity consumed at the Premises, regardless of whether the person is a Customer of a Licence Holder, in respect of the Premises.

"Act" means the *Electricity Act*.

"Behind-the-Meter" means the sale of electricity from a Renewable Low-Impact Electricity Generation Facility which is directly connected to a Customer's load without using NS Power's transmission or distribution facilities, including NS Power's meter installed at the Customer's Premises. For greater certainty, the electricity that is sold from a Renewable Low-Impact Generation Facility to a directly-connected Customer is Behind-the-Meter, while electricity that is sold from the same facility to another Customer through the use of NS Power's transmission or distribution facilities is not Behind-the-Meter.

"Board" means the Nova Scotia Utility and Review Board.

"Bundled-supply" means the Customer is supplied electricity by NS Power.

"Certification" means the electricity standard approval issued by the Minister to a Renewable Low-Impact Electricity Generation Facility under the *Renewable Electricity Regulations*.

"Code of Conduct" means the Code of Conduct for the sale of Renewable Low-Impact Electricity approved by the Board.

"Compliance Period" means the twenty-four month period commencing each January 1. The initial Compliance Period shall commence on the date that a Licence is approved and shall end December 31 of the following year.

"Compliance Plan" means the forecast of Renewable Low-Impact Electricity sales to Customers, purchases from Renewable Low-Impact Electricity Generators, and generation from Renewable Low-Impact Electricity Generation Facilities owned or operated by the Licence Holder.

"Contract" means an agreement between a Customer and a Licence Holder for the supply of Renewable Low-Impact Electricity to a single or multiple Premises.

"Customer" means an Account Holder, or in the case of a Behind-the-Meter installation, the owner of the Premises, who consumes electricity on its Premises that the Account Holder or owner did not generate and

a) with whom a Licence Holder has entered into a Contract; or
b) to whom a Licence Holder is Marketing.

"Day" means calendar day, unless otherwise specified.

"Direct Mail Transaction" means a paper-based transaction

a) initiated by a Licence Holder mailing or transmitting by facsimile documents to a Customer, which mailing or transmitting may be solicited or unsolicited by the Customer, or
b) initiated by a Customer obtaining the form of Contract using Electronic Communication but does not include the completion of the contracting process through Electronic Communication.

"Disclosure Statement" means the information document in the form approved from time to time by the Board pursuant to s. 46 of these Regulations.

"Door-to-Door Transaction" means a transaction initiated by the attendance of a Salesperson at the Premises of a Customer, whether or not this attendance was solicited or unsolicited by the Customer.

"Electronic Communication" means communication created, recorded, transmitted, or stored in digital form or in other intangible form by electronic, magnetic, or optical means or by any other means that has capabilities for creation, recording, transmission, or storage similar to those means. Electronic Communication is primarily conducted over the internet and includes e-mail correspondence.

"Licence" means a Retail Supplier licence issued by the Board to a person to sell Renewable Low-Impact Electricity.

"Licence Holder" means a person issued a Licence by the Board.

"Marketing" means any activity pertaining to the sale of Renewable Low-Impact Electricity for the purpose of soliciting or inducing a Customer to enter into a Contract with a Retail Supplier, including providing an offer for the Customer's consideration, and includes in-person communication, direct mail communication, Electronic Communication, or telephone communication with Customers, advertising, and any other means by which a Retail Supplier or its Salespersons interact with a Customer for the purpose of solicitation.

"NS Power" means Nova Scotia Power, Inc.

"Premises" means the building or portion of a building that is provided with electricity through a single meter.

"Rate" means the amount of money on a ¢/kilowatt-hour basis, plus any fees or charges, to be paid by a Customer.

"Rate Comparison" means the electricity rate comparison information in the form approved from time to time by the Board pursuant to s. 47 of these Regulations that shows the Rate offered by the Retail Supplier, the current Rate charged by NS Power at the time of Marketing, and any other information that the Board may require.

"Regulations" means *Board Electricity Retailers Regulations (Nova Scotia)* enacted under *The Electricity Act*.

"Renewable Low-Impact Electricity" has the same meaning as in the *Renewable Electricity Regulations*.

"Renewable Low-Impact Electricity Generation Facility" has the same meaning as in the *Renewable Electricity Regulations*.

"Renewable Low-Impact Electricity Generator" has the same meaning as in the *Renewable Electricity Regulations*.

"Retail Supplier" has the same meaning as under the Act.

"Retailer-supply" means the Customer is supplied electricity by a Retail Supplier.

"Salesperson" means a person who is employed by or otherwise conducts Marketing on behalf of a Licence Holder, or makes representations to a Customer on behalf of a Licence Holder, for the purpose of effecting sales of Renewable Low-Impact Electricity or entering into a Contract with a Customer.

"Small-Volume Customer" means an Account Holder that qualifies for the Domestic Service or Small General tariffs.

"Telemarketing" means Marketing conducted by a Licence Holder using the telephone, but excludes the initiation of a Direct Mail Transaction by a Customer using the telephone.

"Top-Up Rate" means the rate charged by NS Power to the Licence Holder for non-renewable electricity supplied by NS Power to a Customer.

Interpretation

3

3(1) Where a word or phrase is defined in these Regulations or the Act, other parts of speech and grammatical forms of the word or phrase have a corresponding meaning.

3(2) Headings are for convenience only and do not affect the interpretation of these Regulations.

3(3) Words importing the singular include the plural and vice versa. Words importing a gender include any gender.

3(4) Where there is a reference to a number of Days between two events in these Regulations, the Days shall be counted by excluding the Day the first event happens and including the Day the second event happens.

3(5) The words "include" or "including" are not used, nor are they to be interpreted, as words of limitation.

Requirement for Retail Supplier Licence

4 In accordance with the s. 3D of the Act, any person who acts or purports to act as a Retail Supplier shall hold a valid Licence issued by the Board.

Application for Retail Supplier Licence

5

5(1) An application for a Licence shall be in the form attached (Appendix "A") and shall be accompanied by the following:

a) a cheque in the required amount of $7,500 payable to the Board;
b) an irrevocable letter of credit from a recognized financial institution in the amount of $200,000 payable to the Board to secure performance and anticipated financial obligations of the proposed Licence Holder, or equivalent financial instrument in the same amount payable to the Board if such substitution is approved by the Board;
c) if the applicant is a company, proof of registration under the *Corporations Registration Act,* R.S.N.S. 1989, c. 101;
d) full legal name, address, phone, facsimile, and e-mail contact information of any partner(s) or parent company(s) or organization(s);
e) a listing of any company or organization principals with applicable titles (proprietor, partner, officer, director or controlling shareholder);
f) written consents signed by each proprietor, partner, officer, director, and controlling shareholder authorizing the Board to conduct a credit review, in accordance with standard business practices;
g) written consents signed by each proprietor, partner, officer, director, and controlling shareholder authorizing the Board to consult with all law enforcement agencies and obtain copies of any records pertaining to criminal convictions for which a pardon has not been granted, records of discharge, and records of outstanding criminal charges, such consents to release all such agencies, their members, and employees from any and all actions, claims and demands, loss, or injury which may result from the disclosure of information provided by them;
h) audited financial statements covering the two immediately preceding fiscal years or, if the applicant has been formed within the preceding twelve months and audited financial statements are not available for at least one year, *pro forma* financial statements signed by the proprietor, partner, officer, director, or controlling shareholder of the applicant may be substituted. If audited financial statements are not available, unaudited financial statements may be accepted at the discretion of the Board;
i) the Compliance Plan including copies of the contractual arrangements with Renewable Low-Impact Electricity Generators and copies of the Certification required in s. 17. If contractual arrangements have not been executed, then a letter of intent from a Renewable Low-Impact Electricity Generator to enter into a contract for Renewable Low-Impact Electricity supply may be accepted at the discretion of the Board;

j) a written description of the applicant's business background and experience relating to electricity retailing;
k) a written description of the applicant's general plans with respect to electricity retailing; and
l) any other information which may be deemed necessary by the Board.

5(2) Any variance from the requirements set out in ss. 5(1) shall be formally requested from and approved by the Board prior to an application being submitted.

Term of Licence

6 A Licence shall have no expiration date but a Licence Holder shall be required to file annual statements as specified in s. 22 to confirm the accuracy of information previously filed with the Board regarding that Licence Holder or provide advice of any changes.

Transfer or Assignment of Licence

7

7(1) A Licence may not be transferred or assigned without the written consent of the Board.

7(2) A Licence Holder shall furnish the Board with any information requested by the Board in support of the proposed transfer or assignment of the Licence.

7(3) The fee for the transfer or assignment of a Licence is $7,500.

7(4) The Board may waive the fee set out in ss. 7(3) at its discretion.

7(5) A Licence Holder shall inform NS Power of any application to the Board to transfer or assign a Licence.

Fees and Costs

8

8(1) As set out in ss. 5(1)(a), the fee for a Licence application and first year of operation is $7,500 with annual filing fees of $1,500 in each successive year.

8(2) Fees are payable to the Board when the application for Licence or annual statement as specified in s. 22 is filed with the Board.

8(3) Costs relating to processing, investigations, infractions, inquiries, or enforcement activities which are incurred by the Board and exceed the fees received from a Licence Holder shall be reimbursed to the Board by the Licence Holder involved.

Terms and Conditions of Licences

9 It shall be a term and condition of a Licence that a Licence Holder shall be subject to and comply with

a) the market rules, tariffs, and procedures approved by the Board;
b) the Act, the Renewable Electricity Regulations, and these Regulations;
c) the Code of Conduct approved by the Board pursuant to s. 27;

d) any applicable directives, rules, or orders of the Board; and

e) any direction by the Board for payment of any costs reasonably incurred related to hearing complaints or alleged infractions.

Compliance Period

10

10(1) In each Compliance Period, a Licence Holder's total purchases or, in the case of a Licence Holder that is also a generator, total generation of Renewable Low-Impact Electricity, or combination of purchases and generation, shall equal or exceed the Licence Holder's total sales of Renewable Low-Impact Electricity plus transmission and distribution losses.

10(2) This requirement does not apply to Behind-the-Meter sales.

11

11(1) A Licence Holder shall provide a Compliance Plan to the Board no later than 60 days prior to the start of each Compliance Period that details for the coming Compliance Period

a) the sales plan showing the forecasts of the sales of Renewable Low-Impact Electricity, including numbers of Customers differentiated by NS Power's rate classes and forecasts of sales by Customer, but not including any Behind-the-Meter sales;

b) forecasts of Renewable Low-Impact Electricity purchases from Renewable Low-Impact Electricity Generators;

c) copies of any contractual arrangements with Renewable Low-Impact Electricity Generators demonstrating that the Licence Holder has secured a sufficient supply to meet its forecasts in b);

d) copies of the Certification required in ss.17(1) from each Renewable Low-Impact Electricity Generator that the Licence Holder contracts with;

e) copies of the Certification required in ss.17(2) from each Renewable Low-Impact Electricity Generation Facility that the Licence Holder owns or operates.

f) forecasts of Renewable Low-Impact Electricity generation if the Licence Holder owns or operates a Renewable Low-Impact Electricity Generation Facility, net of any Behind-the-Meter sales; and

g) forecasts of transmission and distribution losses

such that the requirements set out in s. 10 are met.

11(2) Where a Licence Holder is engaged exclusively in Behind-the-Meter sales, ss.11(1) shall not apply, but the Licence Holder shall, 60 days prior to the start of each Compliance Period, file written confirmation with the Board that the Licence Holder will continue to engage exclusively in Behind-the-Meter sales during the upcoming Compliance Period.

12 The Board shall review the Licence Holder's Compliance Plan in order to be satisfied that the Licence Holder can reasonably be expected to meet its obligations as set out in s. 10.

13 If a Licence Holder has not procured or generated sufficient Renewable Low-Impact Electricity to meets its obligations as set out in s. 10, the Licence Holder shall refund to each of its affected Customers or former Customers, based on their consumption of Renewable Low-Impact Electricity, the difference between the Licence Holder's Rate and 90% of the weighted average Top-Up Rate over the Compliance Period, multiplied by the volume of electricity that the Licence Holder is deficient in meeting its obligations to each Customer as set out in s. 10. For greater certainty, the refund to each Customer is to be calculated as the Licence Holder's Rate less 90% of the weighted average Top-Up Rate over the Compliance Period, multiplied by the number of kilowatt-hours that the Licence Holder supplied to each Customer that were not kilowatt-hours of Renewable Low-Impact Electricity.

14 The Board may require a Licence Holder to provide an update of the Compliance Plan at any time.

15 The Board may require a Licence Holder to amend its Compliance Plan or provide additional information if the Compliance Plan is not reasonable in the Board's opinion.

16 A Licence Holder that fails to provide a satisfactory

a) Compliance Plan as set out in ss. 10(1);

b) update to the Compliance Plan as set out in s. 14; or

c) amended Compliance Plan as set out in s. 15

may have its Licence suspended or cancelled as set out in s. 19.

Certification of Renewable Low-Impact Electricity

17

17(1) A Licence Holder that purchases Renewable Low-Impact Electricity from a Renewable Low-Impact Electricity Generator shall obtain proof of Certification from the Renewable Low-Impact Electricity Generator.

17(2) A Licence Holder that generates Renewable Low-Impact Electricity at a Renewable Low-Impact Electricity Generation Facility owned or operated by the Licence Holder shall obtain Certification.

Inquiry Respecting Compliance With Regulations

18 The Board may appoint or direct any duly qualified person to make an inquiry and report upon a Licence Holder's compliance with these Regulations, and may also direct by whom, and in what proportion, the costs and expenses incurred in making the inquiry and report shall be paid, and may fix the amount of the costs and expenses.

Licence Suspension, Cancellation, and Reinstatement

Suspension or Cancellation

19 The Board may cancel or suspend a Licence if it determines that the Licence Holder has contravened the Act, these Regulations, the Code of Conduct, or its Licence.

20 A Licence Holder whose Licence is suspended may no longer conduct Marketing to Customers.

Reinstatement

21 A Licence Holder may apply for reinstatement of a Licence that was suspended as set out in s. 19 if it provides any or all of

a) a plan, satisfactory to the Board, to address and correct contraventions of the Act, these Regulations, the Code of Conduct, or its Licence and prevent future contraventions;

b) a Compliance Plan satisfactory to the Board; or

c) any other information requested by the Board

as directed by the Board.

Reporting

Annual Licensing Reporting

22 A Licence Holder shall provide the following information, as applicable, to the Board no earlier than 60 days and no later than 30 days prior to the anniversary of the Licence:

a) proof of registration under the *Corporations Registration Act,* R.S.N.S. 1989, c. 101;

b) any changes to the full legal name, address, phone, facsimile, and e-mail contact information of any partner(s) or parent company(s) or organization(s), or confirmation that no changes have occurred;

c) any changes to the listing of the company or organization principals with applicable titles (proprietor, partner, officer, director, or controlling shareholder) from the previous year's filing, or confirmation that no changes have occurred;

d) audited financial statements for the most recently completed fiscal year. If audited financial statements are not available, unaudited financial statements may be provided at the discretion of the Board; and

e) any other information which may be requested by the Board.

Compliance Reporting

23

23(1) A Licence Holder shall demonstrate to the Board that the Licence Holder's total purchases or, in the case of a Licence Holder that is also a Renewable Low-Impact

Electricity Generator, total generation of Renewable Low-Impact Electricity, or combination of purchases and generation, equals or exceeds the Licence Holder's obligations as set out in s. 10 after taking into account transmission and distribution losses.

23(2) Within 30 days following the end of each Compliance Period, a Licence Holder shall provide the following information to the Board for the Compliance Period most recently completed:

a) total, in kilowatt-hours, of all Renewable Low-Impact Electricity sales to its Customers;

b) total number of Customers under Contract, differentiated by NS Power's rate classes;

c) total purchases of Renewable Low-Impact Electricity from Renewable Low-Impact Electricity Generators;

d) copies of the written confirmation from the Renewable Low-Impact Electricity Generators documenting quantities of Renewable Low-Impact Electricity purchased by the License Holder;

e) total generation of Renewable Low-Impact Electricity from Renewable Low-Impact Electricity Generation Facilities owned or operated by the Licence Holder;

f) transmission and distribution losses; and

g) a reconciliation of the net surplus or deficit of Renewable Low-Impact Electricity sales with respect to Renewable Low-Impact Electricity purchases, generation, or combination of purchases and generation, and transmission and distribution losses.

23(3) Where a Licence Holder generates and sells Renewable Low-Impact Electricity Behind-the-Meter, the Licence Holder shall provide the information set out in ss.23(2), and shall also provide the total of Behind-the-Meter sales and number of such customers.

23(4) Where a net deficit exists as set out in ss.23(2)(g), the Licence Holder shall provide confirmation to the Board that it has refunded its Customers pursuant to s. 13 within 30 days of the end of the Compliance Period.

24 The Board may request additional information from a Licence Holder at any time.

25 The Board, or its delegate, may, upon notification to a Licence Holder, enter a Licence Holder's place of business in order to inspect the accounts of the Licence Holder and the Licence Holder shall furnish such assistance as the Board or its delegate may reasonably require.

Transfer Requests

26 A Licence Holder shall not make a request to NS Power to transfer a Customer to the Licence Holder's supply unless that Customer has agreed to a Contract with the Licence Holder and the Licence Holder has complied with all the provisions of these

Regulations and the Code of Conduct when Marketing and communicating with that Customer.

Sales and Marketing Practices

Code of Conduct

27

27(1) The Board shall approve a Code of Conduct that shall apply to the Marketing activities of Licence Holders.

27(2) The Code of Conduct may specify

a) the fair Marketing practices that are to be followed by the Licence Holder or its Salespersons when Marketing Renewable Low-Impact Electricity to Customers;

b) requirements for Board approval of Marketing materials and Telemarketing scripts;

c) requirements for Salesperson identification;

d) requirements for testimonials;

e) requirements for Marketing and execution of Contracts;

f) training and product knowledge requirements for Licence Holders and their Salespersons; and

g) any other requirements the Board deems necessary.

27(3) A Licence Holder and its Salespersons shall adhere to the Code of Conduct which has been approved by the Board.

Contracts

Contracting Parties

28

28(1) A Contract for the supply of Renewable Low-Impact Electricity to a Premises may only be made with the Account Holder for that Premises except for Behind-the-Meter sales, where the Contract may be made with the owner of the Premises. Where a Licence Holder enters into a Contract to supply more than one Premises, the Contract must be entered into with the Account Holder or owner for each affected Premises.

28(2) No Contract is valid unless it is made in accordance with ss.28(1) herein.

Governing Laws

29 All Contracts shall be governed by the laws of the Province of Nova Scotia and shall contain a statement to that effect.

Contracting Requirements

30 A Contract takes effect and a Licence Holder is bound by its terms when,

a) for Door-to-Door Transactions or Direct Mail Transactions, a copy of the Contract, signed by the Account Holder, or the owner as the case may be, is received by the Licence Holder or its Salesperson;

b) for Telemarketing sales, the Account Holder, or the owner as the case may be, agrees to the terms and conditions of the Contract while on the telephone with the Licence Holder; and

c) for Electronic Communication sales, the Account Holder, or the owner as the case may be, agrees to the terms and conditions of the Contract through Electronic Communication.

Contract Assignment

31 A Licence Holder shall not assign, sell, or otherwise transfer the administration of a Contract with a Customer to another person unless that person holds a Licence issued under s. 3D of the Act.

32 Within 60 Days after an assignment, sale, or transfer of the administration of a Contract, the new Licence Holder shall send to any affected Customer a notice of assignment, which includes the new Licence Holder's address for service, its e-mail address, and telephone and facsimile numbers.

33 A Licence Holder shall notify the Board of any assignment, sale, or transfer of a Contract within 10 Days after the assignment, sale or transfer.

34 A Licence Holder shall notify NS Power prior to any assignment, sale, or transfer of a Contract taking effect.

Records Retention

Retention of Information

35 A Licence Holder shall keep the following information for as long as the Licence Holder is licensed by the Board plus one additional year:

a) a list of Salespersons who act or who have acted for the Licence Holder and the dates of their employment or engagement;

b) a list of all of the Licence Holder's Customers who have entered into Contracts; and

c) a log of cancellation requests, including Premises to which the cancellation applies, the Account Holder's or owner of the Premises' name, the date of the notification of cancellation, and the name and identification number of the representative who accepted the request for cancellation.

36 For each Customer that has entered into a Contract with a Licence Holder, the Licence Holder shall retain the following information throughout the duration of the Contract and for a period of one year after completion or termination of the Contract:

a) for Contracts agreed to in person or as a result of a Door-to-Door Transaction or a Direct Mail Transaction, a copy of the complete Contract bearing the Customer's signature;

b) for Contracts agreed to as a result of a Telemarketing Transaction, a copy of the agreed-to Contract and the complete recording of the telephone call between the Customer and the Licence Holder;

c) for Contracts agreed to through Electronic Communication, a copy of the agreed-to Contract and the electronic record evidencing the Customer's agreement to the Contract;

d) where a Customer cancels a Contract over the telephone, the complete recording of the telephone call between the Customer and the Licence Holder;

e) where a Customer cancels a Contract using written or Electronic Communication, written or electronic evidence of the communication from the Customer requesting the cancellation; and

f) billing records.

37 A Licence Holder shall, on the request of the Board, provide to the Board any of the information required to be kept under s. 35, s. 36, or s. 54.

Dispute Resolution Process

38 A Customer, NS Power, or any person may make a complaint to the Licence Holder or the Board in respect of the conduct of the Licence Holder, the conduct of the Licence Holder's Salespersons, the Contract, and any other matter relating to the Act, these Regulations, the Code of Conduct, or the Licence.

39

39(1) If a complaint under s. 38 is first made to the Licence Holder, the Licence Holder shall promptly and in good faith investigate the complaint and take all appropriate and necessary steps to resolve the complaint.

39(2) If the complaint is not resolved to the satisfaction of the complainant, the Licence Holder shall inform the complainant that the complaint may be made to the Board and provide the complainant with the telephone number, mailing address, and e-mail address of the Board.

40 Where the Board receives a complaint pursuant to s. 38 the Board may

a) dismiss the complaint if the Board is satisfied that the complaint is trivial or vexatious, or that there is insufficient or no evidence of a contravention of the Act, these Regulations, the Code of Conduct, or the Licence;

b) further investigate the complaint and assist in the resolution of the complaint between the complainant and the Licence Holder; or

c) require a written or oral hearing of the complaint.

41

41(1) Where the Board receives information that a Licence Holder or its Salesperson may have contravened the Act, these Regulations, the Code of Conduct, or its Licence, the Board may initiate a written or oral inquiry into the Licence Holder's or its Salesperson's activities and require the Licence Holder to provide such information or furnish such documents as the Board may request, and produce such officers, directors, employees, and agents to testify as the Board may request.

41(2) The procedure for a written or oral inquiry shall be established by an order of the Board.

42 Following a complaint hearing or inquiry process, the Board shall determine if the Licence Holder or its Salesperson has contravened the Act, these Regulations, the Code of Conduct, or its Licence.

43 If the Board determines that the Licence Holder or its Salespersons have contravened the Act, these Regulations, the Code of Conduct, or its Licence, the Board may impose any or all of the following remedies for each contravention

a) reprimand the Licence Holder;

b) cancel a Contract, with or without fees, penalties or other charges;

c) require the Licence Holder to provide a plan, satisfactory to the Board, to address and correct contraventions of the Act, these Regulations, the Code of Conduct, or its Licence, and prevent future contraventions;

d) instruct the Licence Holder to advise the Customer or any group of Customers affected in a similar manner that they may cancel their Contract without fees, penalties or other charges and be returned to NS Power-supply;

e) suspend or cancel the Licence as set out in s. 19;

f) publish the Board's findings in respect of the contravention and the nature of the remedies imposed; and

g) such further and other remedies as are available to the Board pursuant to applicable laws.

44

44(1) The Board may award costs to or against a Licence Holder or a complainant in connection with the dispute resolution.

44(2) The Board may require a Licence Holder or the complainant, or both, to pay all or a portion of the Board's costs in connection with the dispute resolution.

Requirements For Small-Volume Customers

Marketing to Small-Volume Customers

45 When Marketing to Small-Volume Customers, a Licence Holder shall

a) only use the form of Contract which is approved for use by the Board;

b) for Door-to-Door Transactions, Direct Mail Transactions, or Electronic Communication transactions, provide a Disclosure Statement and Rate Comparison to the Customer as set out in s. 46 and s. 47 in advance of the Customer agreeing to a Contract and shall afford the Customer sufficient time to review and understand the Disclosure Statement and Rate Comparison prior to the Customer signing or agreeing to a Contract; or

c) for Telemarketing Transactions, read to the Customer the Disclosure Statement and Rate Comparison as set out in s. 46 and s. 47 and obtain the Customer's agreement that the Customer understands the Disclosure Statement and Rate Comparison.

Disclosure Statement

46 The Disclosure Statement that is provided to a Small-Volume Customer shall be approved by the Board.

Rate Comparison

47 The Rate Comparison that is provided to a Small-Volume Customer shall be in a form approved by the Board.

Small-Volume Customer Contract Requirements

48 No Contract is valid unless the Small-Volume Customer has signed or agreed to the Disclosure Statement and the Rate Comparison.

49

49(1) A Licence Holder shall not enter into a Contract with a Small-Volume Customer that has a term in excess of five (5) years.

49(2) Subsection.49(1) does not apply to a Contract for Behind-the-Meter sales.

50

50(1) A Contract with a Small-Volume Customer shall state that the Contract is not valid unless:

a) the Customer signs the Disclosure Statement and Rate Comparison or, in the case of a Telemarketing Transaction or Electronic Communication transaction, the Customer confirms that he understands and confirms the Disclosure Statement and Rate Comparison before the Customer enters into the Contract;

b) the Customer signs or agrees to the Contract; and

c) the Licence Holder provides a signed or agreed-to copy of the Disclosure Statement, Rate Comparison, and Contract to the Customer by mail, facsimile, Electronic Communication, or in person.

50(2) A Contract with a Small-Volume Customer shall include a provision that states the Contract is valid only if the Contract has been verified as required in s. 51.

50(3) A Contract with a Small-Volume Customer shall include a provision that the Customer may cancel the Contract without cost or penalty if a Contract presently exists for the same Premises, except where the existing Contract is to expire on or before the commencement of the new Contract.

50(4) A Contract with a Small-Volume Customer shall include a provision that the Customer may cancel the Contract without penalty or charge if the Retail Supplier was not licensed by the Board or the Licence was suspended at the time the Contract was entered into.

Contract Verification

51 A Contract with a Small-Volume Customer shall be verified as set out in s. 52 and s. 53 in order for the Contract to be valid.

Who may verify a Contract

52 A Contract with a Small-Volume Customer may be verified only by an individual who:

a) does not receive any remuneration or other compensation or benefit that is determined, directly or indirectly, by reference to the number of Contracts verified or the percentage of Contracts that are verified; and

b) has successfully completed such training for persons who verify Contracts as may be required by the Code of Conduct, any order, or any rule issued or made by the Board.

Verification process

53

53(1) A Contract with a Small-Volume Customer shall be verified

a) only by telephone; and

b) only with the Account Holder for the Premises.

53(2) The script used by the person verifying the Contract shall be approved by the Board in advance.

53(3) The person verifying the Contract shall comply with the Code of Conduct, any order, or any rule issued or made by the Board relating to the verification procedure.

53(4) The person verifying the Contract shall make a recording of the telephone call and advise the Customer that the telephone call is being recorded.

53(5) A Contract may be verified no earlier than the 10th day and no later than the 21st day after the day on which the Contract takes effect in accordance with s. 30.

53(6) The person verifying the Contract shall not proceed with the verification process and shall advise the Customer and the Licence Holder of the reason for not proceeding if, at any time during the verification process, the person verifying the Contract

a) is advised by the Customer of an act or omission that appears to be an unfair practice of the Licence Holder;

b) is advised that the Customer did not receive a copy of the Contract, the Disclosure Statement, or the Rate Comparison; or

c) has reasonable grounds for believing that the Licence Holder has committed an unfair practice, whether at the time of soliciting, negotiating or entering into the Contract or after.

Records Retention

54 For each Small-Volume Customer that has entered into a Contract with a Licence Holder, the Licence Holder shall retain the following information, in addition to the information as set out in s. 36, throughout the duration of the Contract and for a period of one year after completion or termination of the Contract:

a) in respect of a Contract resulting from a Door-to-Door Transaction or a Direct Mail Transaction, copies of the Disclosure Statement and Rate Comparison bearing the Customer's signature; and

b) in respect of a Contract resulting from Electronic Communication,

i) copies of the confirmed Disclosure Statement and the confirmed Rate Comparison; and

ii) the electronic record evidencing the Customer's confirmation of the Disclosure Statement and Rate Comparison.

Cancellation of Contracts

55

55(1) A Small-Volume Customer, other than a Small-Volume Customer that is directly connected Behind-the-Meter, may unconditionally, and without any cancellation fees, penalties or charges, cancel the Contract at any time from the date of entering into the Contract until 30 Days after the date of the first bill for Renewable Low-Impact Electricity under the Contract, provided the Customer is obligated to pay the Licence Holder for all Renewable Low-Impact Electricity consumed until the Customer is transferred to Bundled-supply.

55(2) A Small-Volume Customer directly connected Behind-the-Meter may unconditionally, and without any cancellation fees, penalties or charges, cancel the Contract within 30 days of the date of entering into same.

56 A Contract with a Small-Volume Customer automatically terminates and the Customer is not subject to any cancellation fees, penalties or charges if the Customer sells or permanently moves from the Premises to which Renewable Low-Impact Electricity is supplied under the Contract.

57 A Small-Volume Customer may unconditionally, and without any cancellation fees, penalties or charges, cancel the Contract if the Licence Holder is found by the Board to be in violation of the Act, these Regulations, the Code of Conduct, or its Licence when Marketing to the Customer or in the course of fulfilling its obligations under the Contract.

58 A Small-Volume Customer may cancel the Contract at any time in accordance with the cancellation provisions contained within the Contract.

59 A Small-Volume Customer may give a notice of cancellation of a Contract in any of the following ways:

a) by telephone;

b) by ordinary or registered mail to the address specified in the Contract;

c) in person;

d) by facsimile to the facsimile number specified in the Contract; or

e) by Electronic Communication to the e-mail address provided in the Contract.

60

60(1) A notice of cancellation in respect of a Contract with a Small-Volume Customer is deemed to be given to the Licence Holder on the date of

a) receipt by the Licence Holder of the telephone call from the Small-Volume Customer cancelling the Contract;

b) the electronic date stamp of the e-mail from the Small-Volume Customer cancelling the Contract;

c) the transmittal of the notice from the Small-Volume Customer cancelling the Contract, if the notice is sent by facsimile;

d) the Day that is five Days after the postmark on the letter from the Small-Volume Customer cancelling the Contract, if the notice is sent by ordinary mail; or

e) the delivery to the Licence Holder of the notice from the Small-Volume Customer cancelling the Contract, if the notice is delivered in person or sent by registered mail.

60(2) The cancellation of a Contract with a Small-Volume Customer, other than a Small-Volume Customer that is directly connected Behind-the-Meter, becomes effective when NS Power transfers the Customer to Bundled-supply.

60(3) The cancellation of a Contract with a Small-Volume Customer that is directly connected Behind-the-Meter becomes effective the earlier of the removal of the Behind-the-Meter installation or 14 days after the date of notice of cancellation is given as set out in ss.60(1).

61

61(1) A Licence Holder shall inform NS Power within 2 business days of a Small-Volume Customer canceling their Contract with the Licence Holder.

62 If a Small-Volume Customer cancels a Contract, the Licence Holder shall promptly provide written confirmation of the cancellation to the Customer.

Prohibition on Contract Renewals

63

63(1) A Contract with a Small-Volume Customer may not be renewed or extended. A new Contract may be entered into between a Small-Volume Customer and a Licence Holder.

63(2) A Contract with a Small-Volume Customer may be terminated prior to the expiration of its term with the consent of the parties and a new Contract may be entered into immediately after the termination. All of the provisions of these Regulations, except as provided in s. 55, apply in respect of the new Contract.

63(3) If a Contract is terminated early and a new Contract is entered into in accordance with ss. 63(2), the Small-Volume Customer may cancel the new Contract at any time from the date of entering into the new Contract until 30 Days after the date of the first bill for Renewable Low-Impact Electricity under the new Contract. The maximum fee, charge or penalty that a Licence Holder may charge the Small-Volume Customer is the cancellation fee as determined under the former Contract at the time of its cancellation.

63(4) If a Contract is terminated early and a new Contract is entered into in accordance with ss. 63(2), the maximum fee, charge or penalty that a Licence Holder may charge the Small-Volume Customer who cancels the new Contract in accordance with s. 58 after the 30-Day period referred to in ss. 63(3) is the cancellation fee as determined under the new Contract.

Notice of Contract Expiry

64 No earlier than four (4) months and no later than three (3) months prior to the contract expiry, the Licence Holder shall notify the Small-Volume Customer of the contract expiry date. At this time, the Licence Holder may offer a new Contract to start after expiry of the current Contract.

CODE OF CONDUCT

FOR RENEWABLE LOW-IMPACT ELECTRICITY SALES IN NOVA SCOTIA

Prepared by Energy Consultants International, Inc.
Brady Ryall, P.Eng.

July 15, 2015

TABLE OF CONTENTS

PURPOSE AND SCOPE

This Code of Conduct for retail sales of renewable low-impact electricity sets out the minimum standards under which a Retail Supplier may sell or offer to sell Renewable Low-Impact Electricity to a Customer.

The purpose of this Code is to foster and uphold a sense of responsibility to the Customer and the general public by all those engaged in Marketing Renewable Low-Impact Electricity in Nova Scotia under the Electricity Act.

This Code applies to all practices used in the Marketing, sale, or offering for sale of renewable low-impact electricity to residential, commercial, and industrial Customers. Where the standards differ amongst classes of Customers based on the amount of electricity used, it is noted.

This Code does not apply to the wholesale Marketing, sale, or offering for sale of renewable low-impact electricity to parties who are not retail customers of such electricity.

This Code is to be interpreted and applied purposively, bearing in mind the varying degrees of knowledge, experience, training, education, age and particular ability of Customers.

1.0 DEFINITIONS AND INTERPRETATION

Definitions

1.1 The following definitions apply in this Code, unless stipulated otherwise.

“Account Holder”, in relation to a Premises, means the person listed on the account of NS Power for the delivery of electricity consumed at the Premises, regardless of whether the person is a Customer of a Licence Holder, in respect of the Premises.

“Act” means the Electricity Act.

“Behind-the-Meter” means the sale of electricity from a Renewable Low-Impact Electricity Generation Facility which is directly connected to a Customer’s load without using NS Power’s transmission or distribution facilities, including NS Power’s meter installed at the Customer’s Premises. For greater certainty, the electricity that is sold from a Renewable Low-Impact Generation Facility to a directly-connected Customer is Behind-the-Meter, while electricity that is sold from the same facility to another Customer through the use of NS Power’s transmission or distribution facilities is not Behind-the-Meter.

“Board” means Nova Scotia Utility and Review Board.

“Code” means the Code of Conduct for the sale of Renewable Low-Impact Electricity approved by the Board.

“Contract” means an agreement between a Customer and a Licence Holder for the supply of Renewable Low-Impact Electricity to a single or multiple Premises.

“Customer” means an Account Holder, or in the case of a Behind-the-Meter installation, the owner of the Premises, who consumes electricity on its Premises that the Account Holder or owner did not generate and

(a) with whom a Licence Holder has entered into a Contract; or

(b) to whom a Licence Holder is Marketing.

“Day” means calendar day, unless otherwise specified.

“Direct Mail Transaction” means a paper-based transaction

(a) initiated by a Licence Holder mailing or transmitting by facsimile documents to a Customer, which mailing or transmitting may be solicited or unsolicited by the Customer, or

(b) initiated by a Customer obtaining the form of Contract using Electronic Communication but does not include the completion of the contracting process through Electronic Communication.

"Disclosure Statement" means the information document in the form approved from time to time by the Board pursuant to s. 46 of the Regulations.

"Door-to-Door Transaction" means a transaction initiated by the attendance of a Salesperson at the Premises of a Customer, whether or not this attendance was solicited or unsolicited by the Customer.

"Electronic Communication" means communication created, recorded, transmitted, or stored in digital form or in other intangible form by electronic, magnetic, or optical means or by any other means that has capabilities for creation, recording, transmission, or storage similar to those means. Electronic Communication is primarily conducted over the internet and includes e-mail correspondence.

"Licence" means a Retail Supplier licence issued by the Board to a person to sell Renewable Low-Impact Electricity.

"Licence Holder" means a person issued a Licence by the Board.

"Marketing" means any activity pertaining to the sale of Renewable Low-Impact Electricity for the purpose of soliciting or inducing a Customer to enter into a Contract with a Retail Supplier, including providing an offer for the Customer's consideration, and includes in-person communication, direct mail communication, Electronic Communication, or telephone communication with Customers, advertising, and any other means by which a Retail Supplier or its Salespersons interact with a Customer for the purpose of solicitation.

"NS Power" means Nova Scotia Power, Inc.

"Premises" means the building or portion of a building that is provided with electricity through a single meter.

"Rate" means the amount of money on a ¢/kilowatt-hour basis, plus any fees or charges, to be paid by a Customer.

"Rate Comparison" means the electricity rate comparison information in the form approved from time to time by the Board pursuant to s. 47 of the Regulations that shows the Rate offered by the Retail Supplier, the current Rate charged by NS Power at the time of Marketing, and any other information that the Board may require.

"Regulations" means *Board Electricity Retailers Regulations (Nova Scotia)* enacted under *The Electricity Act*.

"Renewable Low-Impact Electricity" has the same meaning as in the Renewable Electricity Regulations.

"Retail Supplier" has the same meaning as under the Act.

"Salesperson" means a person who is employed by or otherwise conducts Marketing on behalf of a Licence Holder, or makes representations to a Customer on behalf of a Licence Holder, for the purpose of effecting sales of Renewable Low-Impact Electricity or entering into a Contract with a Customer.

"Small-Volume Customer" means an Account Holder that qualifies for the Domestic Service or Small General tariffs.

"Telemarketing" means Marketing conducted by a Licence Holder using the telephone, but excludes the initiation of a Direct Mail Transaction by a Customer using the telephone.

Interpretation

1.2 Where a word or phrase is defined in this Code or the Act, other parts of speech and grammatical forms of the word or phrase have a corresponding meaning.

1.3 A reference to the Act made in this Code includes any regulations made under the Act.

1.4 Headings are for convenience only and do not affect the interpretation of this Code.

1.5 Words importing the singular include the plural and vice versa. Words importing a gender include any gender.

1.6 Where there is a reference to a number of Days between two events in this Code, the Days shall be counted by excluding the Day the first event happens and including the Day the second event happens.

1.7 The words "include" or "including" are not used, nor are they to be interpreted, as words of limitation.

1.8 A provision in this Code with the heading "Reader's Aid" is included for convenience of reference only and does not form part of this Code.

2.0 LICENCE AND COMPLIANCE

Licence

2.1 Every Retail Supplier operating in Nova Scotia must hold a valid Licence issued by the Board under section 3D of the Act.

Compliance

2.2 A Licence Holder must comply with all applicable provisions of the Act, the Regulations, its Licence, and this Code. Nothing in this Code affects the obligation of a Licence Holder or its Salespersons to comply with all applicable provincial and federal law.

2.3 A Licence Holder must ensure that its Salespersons adhere to the same standards required of the Licence Holder as set out in this Code.

2.4 The standards set out in this Code apply in addition to any other requirements imposed by Law.

Reader's Aid

For provisions that apply only in respect of Small-Volume Customers, see sections 4.1, 4.3, and 4.6; section 5.0; section 7.0; and section 8.0.

3.0 AMENDMENTS AND EXEMPTIONS

3.1 The Board may amend this Code from time to time.

3.2 The Board may grant an exemption from any provision of this Code. An exemption may be made in whole or in part, and may be subject to conditions or restrictions.

4.0 FAIR MARKETING PRACTICES AND TELEPHONE SCRIPTS

Fair Marketing Practices

4.1 When Marketing to a Small-Volume Customer, a Licence Holder must:

(a) at the commencement of Marketing to the Customer:

i) give the name of the Licence Holder and the Salesperson to the Customer;

ii) state that the Licence Holder is not associated with the Nova Scotia Utility and Review Board, the Government of Nova Scotia, or Nova Scotia Power;

iii) if Marketing in a Door-to-Door Transaction:

a. provide a business card to the Customer that meets the requirements of this Code; and

b. display an identification badge that meets the requirements of this Code;

(b) prior to a Contract being signed or agreed to by the Customer, state the Rate to be paid under any offer or proposed Contract for the supply of Renewable Low-Impact Electricity and the term of any proposed Contract;

(c) at all times:

i) not exert undue pressure on the Customer;

ii) provide sufficient time for the Customer to read thoughtfully and without interruption or harassment all documents provided prior to entering into a Contract; and

iii) not use print that because of its size or other visual characteristics is likely to impair the legibility or clarity of documents provided to the Customer.

4.2 When Marketing to a Customer, a Licence Holder must, at all times:

(a) provide only timely, accurate, verifiable, and truthful Rate Comparisons and services;

(b) not mislead, provide untruthful or inaccurate information or otherwise create confusion in the mind of the Customer about the identity of the Licence Holder or its Salesperson, or use the trademarks or identification marks of Nova Scotia Power, the Board, or the Government of Nova Scotia;

(c) not make any representation or statement, give any answer, or take any measure that is false or is likely to mislead the Customer;

(d) not make any representations regarding Contracts, rights, or obligations unless those representations are contained in the Contract;

(e) not make any offer or provide any promotional material to the Customer that is inconsistent with the Contract being offered to the Customer;

(f) not induce the Customer to violate a Contract with another person; and

(g) not exploit the age or lack of knowledge of Canada's official languages by the Customer or the Customer's apparent lack of understanding of an offer or other documents provided to the Customer.

4.3 A Licence Holder must provide a copy of the current version of the Guide – Purchasing Renewable Low-Impact Electricity in Nova Scotia to each Small-Volume Customer:

(a) prior to the customer signing the contract for Door-to-Door Transactions;

(b) by mail or Electronic Communication for Telemarketing transactions or Direct Mail Transactions; or

(c) by providing a prominent internet link that is accessible by the Customer prior to completing the contracting process through Electronic Communication.

4.4 If a Licence Holder's advertising or Marketing materials contain representations about the nature, quality, and price or rate of NS Power's or any Licence Holder's service, or the market price of electricity, the Licence Holder must take reasonable and appropriate steps to ensure that such representations are timely, accurate, verifiable, and truthful.

4.5 A Licence Holder must not enter into a Contract with a Customer that is inconsistent with the offer made to the Customer leading to the Contract.

Telephone Scripts

4.6 Before using a telephone script or any amendment to a script used to verify Contracts as required by s. 53 of the Regulations, the Licence Holder must submit the script or amendment to the Board for approval.

5.0 BUSINESS CARDS AND IDENTIFICATION BADGES

5.1 A Licence Holder must ensure that every Salesperson acting on its behalf and who is Marketing to a Small-Volume Customer in a Door-to-Door Transaction provides the Small-Volume Customer with a business card that meets the requirements set out in s. 5.2 before making any representation to the Small-Volume Customer about the Licence Holder's products, services, or business and before requesting any information about the Customer, including utility bills.

5.2 The business card must be clear and legible and include the following current information:

(a) the name and address of the Licence Holder;

(b) the name of the Salesperson acting on behalf of the Licence Holder;

(c) the toll-free telephone number of the Licence Holder;

(d) the Licence Holder's website; and

(e) the e-mail address of the Licence Holder's customer service department.

5.3 A Licence Holder must ensure that every Salesperson acting on its behalf and who is Marketing to a Small-Volume Customer in a Door-to-Door Transaction at all times wears on the front of the Salesperson's outer clothing an identification badge that meets the requirements set out in s. 5.4.

5.4 The identification badge must be clear and legible and must meet the following requirements:

(a) clearly identify that the Salesperson is acting on behalf of the Licence Holder;

(b) include a photograph of the Salesperson's face that is no older than five years;

(c) identify the Licence Holder; and

(d) identify the name of the Salesperson and the title or position of the Salesperson.

5.5 All of the information set out in s. 5.4 must be shown on the same side of the identification badge and must at all times be facing the Customer.

6.0 TESTIMONIALS AND ENDORSEMENTS

6.1 A Salesperson must not refer to any testimonial, endorsement, or Customer experience that is:

(a) not authorized in writing by the person quoted;

(b) not truthful or not related to the experience of the person giving it;

(c) obsolete or otherwise no longer applicable;

(d) taken out of context; or

(e) provided in any way likely to mislead the Customer.

6.2 For the purpose of ss. 6.1(c), a testimonial, endorsement, or customer experience is obsolete or otherwise no longer applicable if it is more than two years old.

7.0 SMALL-VOLUME CUSTOMER CONTRACTING REQUIREMENTS

7.1 Where a Small-Volume Customer enters into a Contract in a Door-to-Door Transaction, the Licence Holder must provide the following documents to the Customer during the Door-to-Door Transaction:

(a) a signed copy of the Contract;

(b) a signed copy of the Disclosure Statement;

(c) Rate Comparison; and

(d) the current version of the Guide – Purchasing Renewable Low-Impact Electricity in Nova Scotia.

7.2 Within 14 Days of a Small-Volume Customer entering into a Contract as a result of Telemarketing, the Licence Holder must provide the Customer with the following documents by mail, facsimile, or Electronic Communication:

(a) a copy of the agreed-to Contract;

(b) a copy of the confirmed Disclosure Statement;

(c) a copy of the confirmed Rate Comparison; and

(d) the current version of the Guide – Purchasing Renewable Low-Impact Electricity in Nova Scotia.

7.3 For a period of no less than 14 Days from the time when a Small-Volume Customer has entered into a Contract as a result of Electronic Communication, the Licence Holder must permit the Customer to save or print the following documents, as well as provide them to the Customer by Electronic Communication:

(a) a copy of the agreed-to Contract;

(b) a copy of the confirmed Disclosure Statement;

(c) a copy of the confirmed Rate Comparison; and

(d) the current version of the Guide – Purchasing Renewable Low-Impact Electricity in Nova Scotia.

7.4 If a contract is entered into by Electronic Communication, the Licence Holder shall ensure:

(a) that its Electronic Communication, such as its internet website, is secure;

(b) that its Electronic Communication process or server will cancel the Customer's session on the website in a reasonable period of time if the Customer does not continue the session;

(c) that the Electronic Communication includes statements with boxes to be checked off by the Customer in order to proceed with the transaction,

i) that remind the Customer that entering and leaving his or her personal information on a public computer is not recommended,

ii) that confirm that the Customer understands that the Licence Holder does not represent NS Power, the Board, or the Government of Nova Scotia, and

iii) that confirm that the Customer is the Account Holder, or owner of the Premises for Behind-the-Meter sales, with respect to any Contract entered into through Electronic Communication;

(d) that the Electronic Communication provides the terms and conditions of available Contracts, the Disclosure Statement and Rate Comparison applicable to each form of Contract, and a link to the Board's website, without requiring the Customer to commence a transaction;

(e) that, as part of the transaction, the Customer is requested to review the applicable Disclosure Statement and Rate Comparison and indicate that he or she has read and understood these documents by checking a box;

(f) that the Customer has the option to download or print each form of available Contract, Disclosure Statement, and Rate Comparison without any obligation to enter into a Contract;

(g) that the signature page of the Contract contains the electronic signature of an authorized director or authorized officer of the Licence Holder and the date the Contract was entered into by Electronic Communication;

(h) that below the signature contemplated in ss. (g), two boxes are displayed with a request that the Customer check only one, to either,

i) expressly accept the provisions of the Contract, or

ii) expressly decline the Contract and terminate the transaction without completing it; and

(i) that, if the reader checked the box to accept the terms and conditions of the Contract, the Customer is required to provide his or her e-mail address in order to complete the transaction.

8.0 TRAINING AND PRODUCT KNOWLEDGE

8.1 A Licence Holder must ensure that the Licence Holder's Salespersons that engage in Marketing to Small-Volume Customers have sufficient knowledge and training to be able to comply with this Code, the Regulations, and all other applicable legislative requirements.

8.2 No Salesperson shall engage, and no Licence Holder shall allow a Salesperson of that Licence Holder to engage, in any Marketing to a Small-Volume Customer unless the Salesperson has completed the training described in s. 8.1.

9.0 CUSTOMER INFORMATION

9.1 A Licence Holder shall not disclose Customer Information to a third party, other than the Board, without the prior written consent of the Customer, except where the Customer Information is required to be disclosed for the following purposes:

(a) to complete a transfer request with NS Power;

(b) billing;

(c) law enforcement;

(d) complying with a statute or regulation, or an order of a court or tribunal, including the Board; or

(e) the processing of past due accounts of the Customer that have been provided to a debt collection agency.

9.2 Customer Information may be disclosed if it has been sufficiently aggregated such that individual Customer Information cannot reasonably be ascertained.

9.3 A Licence Holder shall not use Customer Information obtained for purposes of Marketing Renewable Low-Impact Electricity to the Customer for any other purpose without the Customer's prior written consent.

10.0 BILLING

10.1 Where a Licence Holder renders bills on behalf of NS Power, the Licence Holder may not mark-up, add to, aggregate, bundle, unbundle, or otherwise alter the Customer-specific line items and charges requested by NS Power.

10.2 Where NS Power renders bills on behalf of a Licence Holder, NS Power may not mark-up, add to, aggregate, bundle, unbundle, or otherwise alter the Customer-specific line items and charges requested by the Licence Holder.

10.3 Where a Licence Holder renders bills on behalf of NS Power, the Licence Holder shall identify on the bill that the Customer-specific line items and charges from NS Power are passed through from NS Power to the Customer without mark-up or profit to the Licence Holder's advantage.

10.4 Where NS Power renders bills on behalf of a Licence Holder, NS Power shall identify on the bill that the Customer-specific line items and charges from the Licence Holder are passed through from the Licence Holder to the Customer without mark-up or profit to NS Power's advantage.

NOVA SCOTIA POWER INCORPORATED

LRS Terms and Conditions

As Approved by the UARB on ●

DRAFT

DRAFT

May 21, 2015 – Version 1

SUBJECT TO NS POWER MANGEMENT REVIEW & APPROVAL

Nova Scotia Power LRS T&Cs

TABLE OF CONTENTS

Contents

1. DEFINITIONS

The following terms shall have the following meanings:

Act: The *Electricity Act*, S.N.S. 2004, c. 25, as amended from time to time.

Ancillary Services: Services that are necessary to support the transport of capacity and energy from generation resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

Billing Period: The time between two consecutive meter readings, or estimates, or a combination thereof, for the RtR Customer.

Board: Nova Scotia Utility and Review Board.

Bundled Service: Electrical service taken from NS Power under NS Power tariffs approved by the Board. This takes the form of having generation, transmission, distribution, Ancillary Services and all other items associated with the provision of such service blended or bundled within the rate.

Business Day: A Business Day is Monday to Friday, inclusive, excluding holidays. The regular business hours on a Business Day are from 08:30 to 16:30 Atlantic Time.

Calendar Day: Any day including Saturday, Sunday or a holiday.

Confidential Information: [NTD derived from Market Rule definition] Information that is (a) designated as confidential in LRS Terms and Conditions or LRS Participation Agreement; or (b) identified in writing as confidential by the disclosing person at the time of disclosure. The following information will not constitute Confidential Information: (i) information which is or becomes generally available to the public other than as a result of a disclosure by NS Power; (ii) information which was already known to NS Power on a non-confidential basis prior to being furnished by the disclosing party; (iii) information which becomes available to NS Power on a non-confidential basis from a source other than the disclosing party or a representative of the disclosing party if such source was not subject to any prohibition against transmitting the information to NS Power and was not bound by a confidentiality agreement with the disclosing party; or (iv) information which was independently developed by NS Power or its representatives without reference to the Confidential Information.

Customer Information: means information including, but not limited to, the name, telephone number, mailing address, e-mail address, service address, site contact name, site contact telephone number and information regarding electricity consumption, class of service and payment history of a Retail Customer or an RtR customer, as applicable.

Demand Side Management (DSM) Recovery Charges: Costs of DSM programs that NS Power is entitled to recover from RtR Customers

Distribution System: NS Power's facilities and equipment (generally rated less than 69 kV) used to distribute electricity to ultimate usage points such as homes and industries either directly from nearby generators or from interchanges from the Transmission System.

Distribution System Access: The services provided by NS Power to the RtR Customer under the Distribution Tariff to provide for the connection of the RtR Customer to the Distribution System for the purpose of receiving renewable low-impact electricity purchased from a LRS to RtR Customers, but does not include the provision of electricity. These services are comprised of delivery of electricity on the distribution system and related services including connections, disconnections, line and service extensions, inspection services, meter services, power restoration, meter reading, and customer service, all in accordance with applicable NS Power Regulations.

Distribution Tariff: The NS Power distribution tariff approved by the Board which provides for Distribution System Access by the RtR Customer for the purpose of receiving renewable low-impact renewable electricity supplied by the LRS.

Distribution Tariff Rate Schedules: The rate schedules attached to the Distribution Tariff which outline the pricing and availability provisions for Distribution System Access.

Embedded Cost Recovery Charges: [NTD: methodology under review]

Energy Balancing Services Tariff: A NS Power tariff, approved by the Board, which provides supplementary generation service to Licensed Retail Suppliers for the delivery of energy to RtR Customers and reception by NS Power of surplus generation from the LRS through qualifying generators. **[NTD Tariff development in progress]**

Good Utility Practice: Those practices, methods or acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America) that at a particular time, in the exercise of reasonable judgment, would have been expected to accomplish the desired result in a manner consistent with regulations, reliability, safety, environmental protection, economy and expedition as applied and practiced in the utility industry with respect to power generation, delivery, purchase and sale.

Licensed Retail Supplier (LRS): A person who:
(a) is authorized to sell renewable low-impact electricity, generated within the province, in accordance with the Act and the regulations made thereunder but does not include a Wholesale Customer;
(b) has been issued a Retail Supplier License by the Board; and
(c) has a valid executed LRS Participation Agreement with NS Power.

For certainty, a Wholesale Customer is not an LRS.

Load Settlement: The process used by NS Power to determine the aggregate consumption of an LRS's RtR Customers in each hour for the purpose of determining charges for services under the Energy Balancing Service Tariff, Standby Service Tariff and for Transmission Services, Ancillary Services and Embedded Cost Recovery under the OATT.

LRS Participation Agreement: The agreement (and any amendments or supplements thereto) between a Licensed Retail Supplier and NS Power in the form attached hereto as Appendix B.

Market Participant: A person who has executed a Participation Agreement (as defined in the Nova Scotia Wholesale Electricity Market Rules Appendix 1A) with the NSPSO in accordance with the requirements of the Nova Scotia Wholesale Electricity Market Rules.

Nova Scotia Wholesale Electricity Market Rules: The Wholesale Market Rules made by the Nova Scotia Department of Energy as amended from time to time in accordance with section 2.4 of those rules.

NS Power: Nova Scotia Power Incorporated.

NS Power Regulations: NS Power Regulations approved by the Board pursuant to the *Public Utilities Act* (Nova Scotia) as such regulations may be amended from time to time with the approval of the Board.

NSPSO: NS Power System Operator.

Open Access Transmission Tariff (OATT): NS Power's Open Access Transmission Tariff, as approved by the Board, which contains the terms, conditions and rates for Transmission Service and Ancillary Services, service and operating agreements, under which service will be provided.

Province: Province of Nova Scotia

Renewable low-impact electricity: Electricity that meets the definition of "renewable low-impact electricity" as defined under the Renewable Electricity Regulations (Nova Scotia).

Retail Customer: A person who (a) uses, for the person's own consumption in the Province, renewable low impact electricity that the person did not generate but does not include a wholesale customer; and (b) is authorized under the Act to purchase renewable low-impact electricity, generated within the province from an LRS. For greater certainty, a customer of a municipal utility (as defined under the Act) is not a Retail Customer.

Retail Supplier License: The retail supplier license issued by the Board in accordance with the Act and regulations made thereunder which permits a person to sell renewable low-impact electricity generated within the Province to RtR Customers.

RtR Customer: A Retail Customer who is acquiring its electricity supply from an LRS and is not receiving Bundled Service from NS Power.

RtR Customer Premises: As the context requires, either:

(a) a complete building such as an office building, factory or house; or

(b) a part of a building such as a suite of offices in an office building or an apartment in an apartment building, and in such cases the part of the building occupied must be contiguous and include no space not controlled by the customer; or

(c) a group of buildings served by one electric service and at its discretion accepted by the Company as one RtR Customer for LRS billing and Load Settlement purposes.

RtR Customer Transaction Request Application: A NS Power document in the form attached hereto as Appendix A to be used by the LRS for the purpose of applying to NS Power to accept and process RtR Customer transactions.

Standby Services Tariff: A NS Power tariff, approved by the Board, which provides **s**upplemental generation capacity service to Licensed Retail Suppliers. The service has two components: (1) capacity adequacy service required to meet adequacy standards of the Nova Scotia electricity system; and (2) top-up capacity service associated with energy delivery in respect of forced or unplanned outages of the Licensed Retail Supplier's contracted generation resources. [NTD: Tariff development in progress.]

Tariffed Services: The services provided to the LRS by NS Power under the Energy Balancing Services Tariff, the Standby Services Tariff, the OATT (including Transmission Service and Ancillary Services) and the Embedded Cost Recovery Tariff. For certainty, the Tariffed Services exclude any services provided to the RtR Customer by NS Power under the Distribution Tariff. [**NTD: Embedded Cost Recovery to be determined**].

Transmission Provider: NS Power.

Transmission Services: The services obtained by market participants under the terms and conditions of the OATT to access the Transmission System for the purpose of transporting electric energy and Ancillary Services.

Transmission System: The facilities, generally rated at 69 kV and above, owned, controlled or operated by the Transmission Provider that are used to provide transmission service under the OATT.

Wholesale Customer: NS Power or a municipal utility (as defined under the Act).

2. PURPOSE OF THE LRS TERMS AND CONDITIONS

These terms and conditions (“LRS Terms and Conditions” or “LRS T&Cs”) are the terms and conditions applicable to Licensed Retail Suppliers for the purpose of enabling the supply of renewable low-impact electricity to RtR Customers in accordance with the provisions of the Act and the regulations made thereunder (“Regulations”).

3. SCOPE AND APPLICABILITY OF THE LRS T&Cs

These LRS T&Cs are applicable to any LRS who enters into an LRS Participation Agreement with NS Power for provision of Tariffed Services to the LRS. This document also addresses procedures for RtR Customer transactions, metering, Load Settlement and LRS billing.

As a Wholesale Electricity Market Participant, the LRS will also be subject to certain requirements set out in the Market Rules in effect for the Wholesale Electricity Market.

4. BOARD APPROVAL

The LRS T&Cs have been approved by the Board.

Nothing contained in the LRS T&Cs or the LRS Participation Agreement shall be construed as affecting in any way the right of NS Power to unilaterally make application to the Board for a change in any rates, terms and conditions, the LRS Participation Agreement, rules or regulations, including the Tariffed Services, Distribution System Access or the Distribution Tariff.

5. APPENDICES

For greater certainty, the following appendices are attached to and form part of the LRS T&Cs:

(a) Appendix A: RtR Customer Transaction Request Application Form
(b) Appendix B: LRS Participation Agreement

6. ELIGIBILITY OF THE LRS

Subject to the terms and conditions set out herein, an LRS shall be eligible for Tariffed Services from NS Power, if the following conditions are met to the satisfaction of NS Power:

(a) LRS has a valid Retail Supplier License and provides NS Power with its unique license identification number;

(b) NS Power is in receipt of a LRS Participation Agreement duly executed by the LRS and NS Power;

(c) LRS meets and adheres to the credit, deposit and security requirements of NS Power as described in Article 17 herein; and

(d) LRS provides NS Power with confirmation that the LRS has been qualified by the NSPSO as a Market Participant within the NS Power operating area.

NS Power shall have the right to terminate the LRS Participation Agreement and discontinue the Tariffed Services without liability or penalty if at any time the LRS fails to satisfy any of the above noted conditions.

NS Power will recognize only one LRS in respect of an RtR Customer Premises at any given time.

7. LRS PARTICIPATION IN NS POWER TARIFFS

The LRS shall subscribe to all Tariffed Services.

Distribution System Access under the Distribution Tariff is provided directly to the RtR Customer by NS Power and is not included in the scope of the LRS Participation Agreement. NS Power may authorize the LRS to invoice the LRS's RtR Customers for any charges or fees owing by the RtR Customers to NS Power ("NS Power Charges") under the Distribution Tariff and to consolidate such charges and fees on the LRS's invoice to the RtR Customer, as detailed in Article 13.1 herein.

8. LRS RESPONSIBILITIES

The LRS shall be responsible for:

(a) the procurement of electricity from eligible low-impact renewable electricity generators;

(b) acquiring the services delivered under, and remaining in compliance with, the OATT, Energy Balancing Service Tariff and the Standby Services Tariff to enable delivery of electricity to the RtR Customer;

(c) payment of invoices issued by NS Power;

(d) adhering to the credit, deposit and security requirements of NS Power as described in Article 17;

(e) obtaining and providing the RtR Customer's written consent, in a form acceptable to NS Power, in support of any transaction requests made to NS Power on behalf of the RtR Customer;

(f) obtaining any consents from the RtR Customer required by NS Power with respect to the use or disclosure of Customer Information;

(g) providing NS Power with up-to-date RtR Customer Information for all customers served by the LRS;

(h) acting as the point of contact for RtR Customers served by the LRS;

(i) ensuring that its RtR Customers are aware of the terms and conditions of any NS Power tariff to which the LRS subscribes that may affect the RtR Customer;

(j) ensuring that the RtR Customers are aware of their responsibilities under the NS Power Regulations; and

(k) notifying NS Power of any changes in its RtR Customers, including the discontinuance of service to a RtR customer by the LRS.

8.1. LRS Arrangements with RtR Customers

The LRS shall be solely responsible for having appropriate contractual or other arrangements with RtR Customer(s) necessary to supply renewable low-impact electricity to RtR Customers. NS Power shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements between the LRS and its RtR Customers and shall not be liable for any loss, damages, cost, injury, expense or other liability, whether direct, indirect, consequential or special in nature, howsoever caused, as a result of either the LRS or the RtR to perform or otherwise satisfy its obligations to the other party. The LRS shall at all times indemnify, defend, and save NS Power, its officers, directors and affiliates, harmless from, any and all damages, losses, claims arising from the LRS's failure to perform its obligations to its RtR Customers.

The LRS must adhere to the requirements of the applicable NS Power Regulations as identified herein.

9. NS POWER RESPONSIBILITIES

NS Power shall be responsible for:

(a) processing all RtR Customer Transaction Request Applications that are received;

(b) providing metering services;

(c) performing Load Settlement for each LRS;

(d) issuing invoices to the LRS;

(e) maintaining Customer Information for all customer sites that are subject to Load Settlement;

(f) maintaining Customer Information as it is supplied and updated by the RtR Customer.

9.1. **Interruption of Tariffed Services**:

NS Power shall provide a regular and uninterrupted delivery of Tariffed Services but shall have no liability to the LRS for any loss or damage arising, either directly or indirectly, from any failure of delivery in respect of any abnormality, delay, interruption or other partial or complete failure in the said delivery. Notwithstanding any term herein, NS Power shall have the right to suspend the delivery of any or all Tariffed Services for the purpose of safeguarding life or property, for making repairs, changes, renewals, improvements or replacements to the Transmission System or Distribution System provided NS Power shall make commercially reasonable efforts to ensure all such interruptions are of a minimum duration consistent with the exigencies of the case. Provided, however, any such interruptions shall not release the LRS from its obligation to pay all charges pursuant to any NS Power tariffs applicable to the Tariffed Services during the period of any such suspensions.

10. RTR CUSTOMER TRANSACTIONS

Prior to the enrolling of a new RtR Customer or modifying the enrollment of an existing RtR Customer, the LRS shall complete and submit to NS Power an RtR Customer Transaction Request Application, in a form acceptable to NS Power, duly executed by the LRS and the RtR Customer. NS Power will review the RtR Customer Transaction Request Application and notify the LRS upon its acceptance or rejection. For certainty, completed RtR Customer Transaction Request Applications are required for the following categories of transactions:

(a) A request to enroll a current NS Power Bundled Service customer as an RtR Customer of the LRS at the current RtR Customer Premises;

(b) A request to enroll a Retail Customer, that is not currently an NS Power Bundled Service customer, as an RtR Customer of the LRS;

(c) A request for return of the LRS's RtR Customer to NS Power's Bundled Service;

(d) A request, initiated by the LRS of record, to transfer an existing RtR Customer from the current LRS to another LRS (Assignee), subject to the written authorization of the Assignee;

(e) A request to obtain Customer Information from NS Power;

(f) A request for NS Power to provide an update of RtR Customer Information; and

(g) Other service request types as determined by NS Power.

The LRS shall provide complete RtR Customer Information with each application for RtR Customer enrollment.

NS Power reserves the right to refuse to accept an RtR Customer Transaction Request Application for any Retail Customer who has outstanding debt payable to NS Power in relation to previous electric service at the Retail Customer Premises identified in the RtR Customer Transaction Request Application.

RtR Customer Transaction Request Applications will be processed based on the order in which they are received by NS Power. If an enrollment is accepted, NS Power will notify the LRS. Upon acceptance of an RtR Customer Transaction Request Application, NS Power will record and recognize the LRS as the LRS of record for the particular RtR Customer Premises. If an RtR Customer Transaction Request Application is rejected, NS Power will provide the LRS with the reason(s) for the rejection.

Following acceptance of the Customer Transaction Request Application by NS Power, the RtR Customer transactions will be effective for the period following the next meter reading for the RtR Customer.

The LRS will not be liable to NS Power for any outstanding indebtedness of the RtR Customer to NS Power in respect of any NS Power electrical service to the RtR Customer which accrued prior to NS Power's acceptance of the enrollment of the RtR Customer with the LRS.

11. LRS RTR CUSTOMER INFORMATION INQUIRIES

11.1. Provision of NS Power Customer Information to LRS

Subject to receipt of the consent of the Retail Customer, NS Power will provide Customer Information to an LRS with which it has an executed LRS Participation Agreement.

An LRS with a fully executed LRS Participation Agreement with NS Power may request Customer Information prior to the RtR Customer subscribing with the LRS provided the RtR Customer has consented in writing to the disclosure of such information to the LRS.

The LRS shall initiate this request by submitting an RtR Customer Transaction Request Application.

11.2. Provision of RtR Customer Information between the LRS and NS Power

The LRS shall notify NS Power promptly of any changes to the Customer Information.

NS Power and the LRS shall supply to each other data, materials or other information that may be reasonably required.

12. METERING

12.1. Provision and Ownership

NS Power will install and seal all revenue class meters for the purpose of measuring the RtR Customer's load as necessary for application of the applicable NS Power tariffs. The meters will be used for determining charges for the RtR Customer's Distribution System Access and also for Load Settlement and billing of the LRS for Tariffed Services.

Interval meters with remote polling capability shall be installed for all RtR Customers. NS Power will charge separate fees for such services or devices.

Meters and associated revenue metering equipment shall remain the property of NS Power.

NS Power Regulations with respect to metering shall apply to metering of RtR Customer loads for the purpose of billing the LRS for Tariffed Services.

12.2. Meter Reading

NS Power shall use commercially reasonable efforts to take an actual meter reading for each RtR Customer Premises in accordance with NS Power's meter reading schedule.

If NS Power is unable to obtain a meter reading, the amount of power and energy used by the RtR Customer in the billing period shall be estimated by NS Power.

At the request of the LRS, NS Power shall use commercially reasonable efforts to obtain an actual meter reading, at a time other than the regularly scheduled meter reading. NS Power will charge the LRS for additional meter reading expense in accordance with NS Power Regulation 7.1 - Schedule of Charges.

NS Power Regulations with respect to meter reading shall apply to metering of RtR Customer loads for the purpose of billing the LRS for Tariffed Services.

13. LRS BILLING AND SETTLEMENT

13.1. Billing of RtR Customers

In order that the LRS may bill its RtR Customers for the sale of renewable low-impact electricity, NS Power will provide to the LRS the metering data for each of the LRS's individual RtR Customers.

All amounts payable by the RtR Customer to NS Power under the Distribution Tariff will be calculated by NS Power using the RtR Customer's meter readings and the Distribution Tariff Rate Schedule applicable to the RtR Customer's rate class.

NS Power may authorize the LRS to invoice the LRS's RtR Customer for any charges or fees, inclusive of all applicable taxes, owing by the RtR Customer to NS Power ("NS Power Charges") under the Distribution Tariff and to consolidate such charges and fees on the LRS's invoice to the RtR Customer.

NS Power charges will be invoiced to the LRS by NS Power and passed-through to the RtR Customer by the LRS and identified on the RtR Customer's bill as NS Power Distribution Tariff charges. The charges will be shown on the invoice to the customer as an itemized list indicating, for each tariffed charge listed, the metered billing determinants, the Distribution Tariff rate applicable, the total amount of the charge. Charges related to special customer services will be itemized and provide the total amount of the charge. The invoice will also provide a final total including taxes for the Distribution Tariff charges applicable the RtR Customer.

In the absence of an arrangement authorizing the consolidation of Distribution Tariff charges as outlined above, NS Power reserves the right to invoice the RtR Customer directly for such charges.

The RtR Distribution Tariff charges include:

(a) Distribution System Access;

(b) Demand Side Management Recovery Charges; and [**NTD: To be determined**];

(c) Other items as may be approved by the Board.

NS Power may, at its discretion, include fees for any special customer services, pursuant to NS Power Regulation 7.1 - Schedule of Charges.

13.2. NS Power Settlement and Billing to LRS for Aggregated Charges

Charges for Tariffed Services for the LRS shall be based on the aggregated RtR Customer. The charge determinant is based on the aggregate of an LRS's RtR Customer loads (total energy, peak hourly aggregate demand). NS Power will invoice for each of the services provided to the LRS under the Energy Balancing Service Tariff and Standby Services Tariff in accordance with the rates, terms and conditions set out in those tariffs.

NS Power will invoice the LRS for Transmission Service, associated Ancillary Services and Embedded Cost Recovery in accordance with the rates, terms, riders and conditions set out in the OATT and in accordance with the Nova Scotia Wholesale Electricity Market Rules and Procedures.

13.3. Settlement Methodology for Determining the Aggregated Charges

To determine the charges described in Section 13.5, NS Power shall determine the aggregate load per hour for the total of all RtR Customers of the LRS.

To determine the aggregated LRS hourly load profile for RtR Customers using interval meters, NS Power will aggregate the individual meter interval readings for each hour in the billing period. The aggregated hourly load profile will be used in the settlement calculations.

13.4. Determination of RtR Load Requirement at Transmission Voltage

Meter readings for distribution-connected RtR Customer loads will be adjusted for distribution losses using established average annual rate class losses for the purpose of LRS Load Settlement for each of the Tariffed Services which are applicable at the transmission voltage level.

13.5. NS Power Billing Procedure:

Within a reasonable time after the first day of each month, the NS Power shall submit an invoice to the LRS for the charges for all Tariffed Services received by the LRS during the preceding month. If NS Power has authorized the LRS to invoice the RtR Customer for charges under the Distribution Tariff, NS Power will invoice the LRS for the Distribution Tariff charges applicable to the LRS's RtR customers. The invoice shall be paid by the LRS to NS Power within 20 Calendar Days of receipt. All payments shall be made in immediately available funds payable to the NS Power.

Each invoice shall state the period to which the invoice applies and describe the services provided. Where practicable, NS Power will address credits and payment obligations due under any tariff on the same invoice through netting, including interest payments or credits.

13.6. Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified in NS Power Regulation 5.4. When payments are made by mail, bills shall be considered as paid on time if the envelope is postmarked on or before the last date for net payment.

14. DEFAULT

In the event the Licensed Retail Supplier fails, for any reason other than a billing dispute as described below, to make payment to NS Power on or before the due date as described above, and such failure of payment is not corrected within 30 Calendar Days after NS Power notifies the Licensed Retail Supplier to cure such failure, a default by the Licensed Retail Supplier shall be deemed to exist. Upon the occurrence of a default by the Licensed Retail Supplier, NS Power may discontinue the Tariffed Services and terminate the LRS Participation Agreement without any liability or responsibility whatsoever, except for obligations arising prior to the date of termination. In the event of a billing dispute between NS Power and the Licensed Retail Supplier, NS Power will continue to provide Tariffed Services as long as the Licensed Retail Supplier (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Licensed Retail Supplier fails to meet these two requirements for continuation of service, then NS Power may provide notice to the Licensed Retail Supplier of its intention to suspend Tariffed Service in 30 days.

15. DISCONTINUANCE OF TARIFFED SERVICES TO LRS

In addition to its rights of discontinuation and suspension under Article 14 herein, NS Power may immediately discontinue Tariffed Services to an LRS and terminate the LRS Participation Agreement if:

(a) The LRS's Retail Supplier License has been suspended, revoked or otherwise cancelled;

(b) The LRS defaults in the performance of its obligations in respect of the Tariffed Services, the LRS T&Cs, or the LRS Participation Agreement;

(c) The LRS fails to make payment to NS Power of any invoices issued to the LRS for the Distribution Tariff charges applicable to the LRS's RtR Customers;

(d) The LRS has failed to meet or maintain the creditworthiness requirements set out in Article 17;

(e) the LRS is disqualified (or no longer qualifies) as a Market Participant within the NS Power operating area;

(f) Termination of the LRS Participation Agreement; or

(g) The LRS fails to adhere to the NS Power Regulations identified herein as applicable to the LRS.

Upon discontinuance of Tariffed Service to the LRS of record, and in the absence of an RtR Customer Transaction Request Application accepted by NS Power requesting the RtR Customer be assigned to an alternate LRS, the provision of Bundled Service to the affected RtR Customers(s) will be assumed by NS Power as the default supplier, in accordance with NS Power's Regulations. **[NTD Business processes will define timelines]**

In addition to any other rights and remedies set out herein, in an event of default by the LRS (including the failure to make payment to NS Power of any invoices issued by NS Power to the LRS for the Distribution Tariff charges applicable to the LRS's RtR customers) the full amount of any security provided by the LRS to NS Power under Article 17 shall become due and payable to NS Power and NS Power shall be entitled to make demand or claim against the LRS's security for the full amount secured thereunder.

All funds received by NS Power in respect of such claim shall be retained by NS Power and applied against the LRS's payment obligations (including payment of any invoices issued by NS Power to the LRS for the Distribution Tariff charges applicable to the LRS's RtR customers) until such time as all of the LRS's obligations have been satisfied.

In the event an RtR Customer breaches, defaults upon or otherwise fails to adhere to NS Power Regulations ("Defaulting RtR Customer"), NS Power shall have the right, without liability or penalty, to immediately terminate or suspend any service to the Defaulting RtR Customer upon notice in writing to the LRS.

16. DISCONTINUANCE OF SERVICE TO RTR CUSTOMER BY THE LRS

To discontinue Tariffed Services to an RtR Customer Premises, an LRS shall complete and provide to NS Power, an RtR Customer Transaction Request Application, in accordance with Article 10. **[NTD Business processes will define timelines]**

The LRS is responsible to ensure that its RtR Customers are provided notice of the request to discontinue provision of service to that RtR Customer, and the consequences thereof. NS Power will not be held liable for any RtR Customer disputes with the LRS.

The Tariffed Services and Distribution System Access shall continue in effect and the LRS shall remain responsible for payment of the Tariffed Services until the next meter reading is obtained. If NS Power has received and accepted an RtR Customer Transaction Request Application from an alternate LRS ("Assignee") for the RtR Customer, that Assignee will be appointed as the new LRS of record for the RtR Customer, otherwise the RtR Customer will be reverted to NS Power Bundled Service.

17. CREDITWORTHINESS [NTD from OATT]

For the purpose of determining the ability of the LRS to meet its obligations related to Tariffed Services service hereunder, NS Power may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, NS Power may require the LRS to provide and maintain in effect during the term of the LRS Participation Agreement, an unconditional and irrevocable letter of credit as security to meet the aggregate of its responsibilities and obligations under each of the Tariffed Services, or an alternative form of security acceptable to NS

Power and consistent with commercial practices established under the law of the Province that protects NS Power against the risk of non-payment.

[NTD: Form of security/credit details are being drafted by NS Power]

18. FORCE MAJEURE AND INDEMNIFICATION

[NTD: These provisions are being drafted by NS Power]

APPENDIX A: RTR CUSTOMER TRANSACTION REQUEST APPLICATION FORM

[N**TD: This will be used by the LRS to initiate a RtR Customer service transaction with NS Power. The final form will include the required information to enable processing of RtR Customer Transaction Request Applications by NS Power. In addition, it will provide for the LRS's and RtR Customer's authorization of the transaction request and their acceptance of the relevant terms and conditions and any fees associated with the completion of the requests. As with all Renewable to Retail documentation it will be subject to UARB review].**

It is expected that the application form will address, as examples:

- Identification of the selected/de-selected supplier for the RtR Customer (initial or transfer to alternate supplier)
- Service action requested: customer usage information, enroll, transfer, etc.
- RtR Customer Information updates by LRS
- Data and information required for each transaction and the format of the data.

The RtR Customer Transaction Request Application will be created in concert with development of NS Power business processes and will incorporate interaction with supplier licensing provisions, as required.

APPENDIX B: LRS PARTICPATION AGREEMENT

LRS Participation Agreement ("Agreement")

THIS PARTICIPATION AGREEMENT ("Agreement") dated this ____ day of ________________, 20__ ("Effective Date")

BETWEEN:

[Name of Licensed Retail Supplier],

(hereinafter referred to as the "Licensed Retail Supplier" or "LRS")

-and-

Nova Scotia Power Incorporated ("NS Power"), a body corporate organized under the laws of the Province of Nova Scotia.

RECITALS:

A. The LRS has been issued a valid Retail Supplier License by the Board under the *Electricity Act* (Nova Scotia) dated **[insert date]** and bearing license number **[insert license number]**; and

B. The LRS wishes to sell renewable low-impact electricity, generated within the Province, to Retail Customers in accordance with the Act and the regulations made thereunder; and

C. The LRS and NS Power wish to enter into this Agreement in accordance with the LRS Participation Terms and Conditions and the Tariffed Services to enable the sale of renewable low-impact electricity by the LRS to Retail Customers.

NOW THEREFORE, in consideration of the mutual covenants in this Agreement and of other good and valuable consideration, the receipt and adequacy of which is hereby acknowledged, the parties agree as follows:

ARTICLE 1

LRS PARTICIPATION TERMS AND CONDITIONS

1.1 Paramountcy: In the event of any inconsistency between this Agreement and the LRS Terms and Conditions, the LRS Terms and Conditions shall prevail to the extent of the inconsistency. The LRS Terms and Conditions are published on NS Power's website at: http//xxxx.xx.[NTD Insert when address is known]

1.2 Definitions: All capitalized terms utilized in this Agreement shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

1.3 Recitals: The recitals shall form an integral part of this Agreement.

ARTICLE 2

COMPLIANCE WITH LRS TERMS AND CONDITIONS

2.1 This Agreement is subject to the LRS Terms and Conditions, as amended from time to time, which is deemed to form a part of this Agreement and is hereby incorporated by reference.

2.2 The execution of this Agreement by the LRS shall constitute acceptance by the LRS of the LRS Terms and Conditions. The LRS acknowledges that it has received a copy of the LRS Terms and Conditions, has reviewed and understands the LRS Terms and Conditions and agrees to be bound by same and any amendments thereto. The LRS agrees to comply with the LRS Terms and Conditions.

ARTICLE 3

QUALIFICATION FOR TARIFFED SERVICES

3.1 The LRS warrants and agrees that all LRS conditions and prerequisites for eligibility for Tariffed Services as provided for in the LRS Terms and Conditions Article 6 have been met as of the date of this Agreement and at all times during the term of this Agreement.

3.2 The LRS agrees that subscription to the Energy Balancing Services Tariff, Standby Services Tariff, Embedded Cost Recovery Tariff and the Open Access Transmission Tariff by the LRS is compulsory.

3.3 The LRS agrees to comply with the billing and settlement procedures and to pay in a form and manner acceptable to NS Power all rates, charges, invoices or fees billed by NS Power for the Tariffed Services in accordance with the LRS Terms and Conditions.

DRAFT

ARTICLE 4

CREDIT REQUIREMENTS

4.1 The LRS has provided NS Power with, and shall maintain, sufficient financial security in accordance with the terms of the LRS Terms and Conditions. **[NTD: To be finalized pending finalization of the creditworthiness provisions in the LRS Terms and Conditions]**

ARTICLE 5

CUSTOMER INFORMATION AND CONFIDENTIALITY

5.1 The LRS is solely responsible for the provision of accurate and timely Customer Information to NS Power.

5.2 The LRS and NS Power agree that Customer Information is Confidential Information and may not be used or disclosed for any purpose without the permission of the RtR Customer.

ARTICLE 6

ARTICLE 6

DEFAULTS AND REMEDIES

6.1 The LRS acknowledges the rights and obligations of NS Power and the LRS should either party default in the performance of its obligations under this Agreement, as set out in the LRS Terms and Conditions.

ARTICLE 7

TERMINATION

7.1 Subject to section 8.2, this Agreement shall automatically terminate on:

(a) the discontinuance of the Tariffed Services by NS Power in accordance with Articles 14 or 15 of the LRS Terms and Conditions; or

DRAFT

(b) the LRS ceasing to be a Market Participant in accordance with section 2.1.6 of the Nova Scotia Wholesale Electricity Market Rules; or

(c) the LRS ceasing to be eligible for Tariffed Services under the LRS Terms and Conditions.

7.2 Notwithstanding section 8.1, if the Agreement is terminated, the LRS shall remain subject to any confidentiality provisions contained in the LRS Terms and Conditions with respect to all Confidential Information obtained by or provided to the LRS while the LRS was a Party to the Agreement. For certainty, all confidentiality obligations of the LRS under the LRS Terms and Conditions shall survive the termination or expiry of this Agreement.

7.3 Notwithstanding any term or condition of this Agreement, if an RtR Customer breaches, defaults upon or otherwise fails to adhere to any of the NS Power Regulations ("Defaulting RtR Customer"), NS Power shall have the right, without liability or penalty, to immediately terminate or suspend Distribution System Access to the Defaulting RtR Customer.

ARTICLE 8

MISCELLANEOUS

8.1 **Amendment:** No amendment of this Agreement shall be effective unless made in writing and signed by the Parties.

8.2 **Assignment:** The LRS may not assign or transfer, whether absolutely, by way of security or otherwise, all or any part of its rights or obligations under this Agreement without the prior written consent of NS Power.

8.3 **Successors and Assigns:** This Agreement shall enure to the benefit of, and be binding on, the Parties and their respective heirs, administrators, executors, successors and permitted assigns.

8.4 **Further Assurances:** Each Party shall promptly execute and deliver or cause to be executed and delivered all further documents in connection with this Agreement that the other Party may reasonably require for the purposes of giving effect to this Agreement.

8.5 **Waiver:** A waiver of any default, breach or non-compliance under this Agreement is not effective unless in writing and signed by the Party to be bound by the waiver. No waiver will be inferred or implied by any failure to act or by the delay in acting by a Party in respect of any default, breach or non-observance or by anything done or omitted to be done by the other Party. The waiver by a Party of

DRAFT

any default, breach or non-compliance under this Agreement shall not operate as a waiver of that Party's rights under this Agreement in respect of any continuing or subsequent default, breach or non-observance (whether of the same or any other nature).

8.6 **Severability:** Any provision of this Agreement that is invalid or unenforceable in any jurisdiction shall, as to that jurisdiction, be ineffective to the extent of that invalidity or unenforceability and shall be deemed severed from the remainder of this Agreement, all without affecting the validity or enforceability of the remaining provisions of this Agreement or affecting the validity or enforceability of such provision in any other jurisdiction.

8.7 **Notices:** Any notice, demand, consent, request or other communication required or permitted to be given or made under this Agreement shall be given in writing and must be given by personal delivery, registered mail or facsimile transmittal as follows:

To NS Power: Nova Scotia Power Inc.
Attention: Corporate Secretary
Address: 1223 Lower Water Street
Halifax, NS B3J 3S8
Facsimile: XXX-XXX-XXXX
Telephone:

To LRS: Retailer
Address
Attention:
Facsimile:

or to such address, facsimile number, or individual as may be agreed between the parties in writing.

8.8 **Governing Law:** This Agreement shall be governed by and construed in accordance with the laws of the Province of Nova Scotia and the federal laws of Canada applicable therein.

8.9 **Counterparts:** This Agreement may be executed by the Parties hereto in counterparts, each of which when so executed and delivered shall be deemed to be an original and when taken together shall be deemed to be one and the same instrument. The electronic delivery, including, without limitation, by email or facsimile transmission, of any signed original of this Agreement shall be the same as the delivery of an original.

IN WITNESS WHEREOF the Parties have, by their duly appointed and authorized representatives, executed this Agreement effective as of the Effective Date.

[INSERT NAME OF LICENSED RETAIL SUPPLIER]

Date:_____________________________

Signature: ________________________

Name: ___________________________

Title: ____________________________

NOVA SCOTIA POWER INCORPORATED

Date: ____________________________

Signature: ________________________

Name: ___________________________

Title: ____________________________

Date: ____________________________

Signature: ________________________

Name: ___________________________

Title: ____________________________

DRAFT

Nova Scotia Power Inc.

2015 Renewable to Retail Proceeding

Distribution Tariff Rate Strawman Report

DRAFT – subject to NS Power management review and approval

May 21, 2015

Nova Scotia
POWER
An Emera Company

TABLE OF CONTENTS

ATTACHMENTS

1.0 INTRODUCTION

This Strawman Report discusses the process and methodology used by Nova Scotia Power (NS Power, the Company) in development of a distribution tariff (DT) applicable to Renewable to Retail (RtR) Customers[1].

The DT is being developed in consultation with stakeholders consistent with s. 3G (1) of the Electricity Act (Nova Scotia) (Act). The Company is seeking to arrive at a consensus among the Company and stakeholders in advance of the Company's filing with the UARB.

The DT is intended for use by distribution-connected RtR customers. It includes terms, conditions and rates under which Distribution System Access will be provided. The DT design is consistent with the cost allocation and tariff design included in rates for customers who continue to take bundled electric service from NS Power.

1.1 Terms and Conditions

The DT contains both rates and terms and conditions. NS Power based the terms and conditions in the DT on existing approved documents, adjusting them for the unique features and participants in the Renewable to Retail Market. RtR Customers who take Distribution System Access are also subject to NS Power Regulations[2] as applicable.

[1] A RtR Customer is a Retail Customer purchasing renewable energy from a Licensed Retail Supplier. A RtR customer is a subset of "Retail Customer" defined under s. 2(1) of the *Electricity Act* (Nova Scotia) as "…a person who uses, for the person's own consumption in the Province, electricity that the person did not generate." . Licensed Retail Suppliers (LRS) LRSs are persons who are licensed by the Nova Scotia Utility and Review Board (UARB, Board) to sell renewable low-impact electricity, as provided for under the Electricity Act (Nova Scotia) (Act).

[2] NS Power Regulations are approved by the UARB and may be found at http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/rates/default.aspx

Attachment A contains the Draft Distribution Tariff Terms and Conditions. **Attachment B** contains the Draft Distribution Tariff Rates.

RtR Customers purchase electricity from Licensed Retail Suppliers (LRS) who supply renewable low-impact electricity generated in Nova Scotia. Each LRS will be licensed by the UARB and will be subject to other tariffs, rules and procedures governing use of the NS Power system and NS Power tariffed services. Those tariffs, rules and procedures will also be developed in consultation with stakeholders and submitted for approval to the UARB.

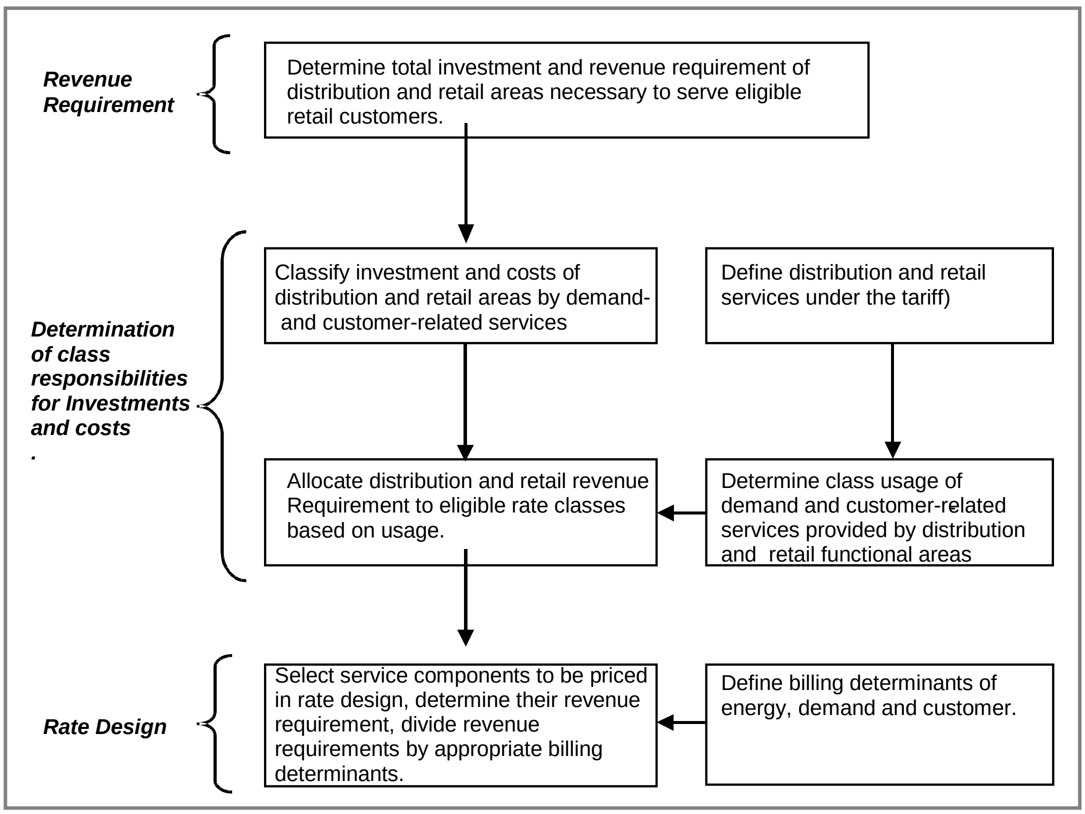
1.2 Rates

In the development of the DT Rates, the Company sought to leverage the existing ratemaking processes used in the Open Access Transmission Tariff (OATT) and General Rate Applications (GRA) while seeking an appropriate balance among competing ratemaking objectives. The Company sought to design rates which are cost based, fairly apportion cost responsibilities among customer classes and customers within each class, are simple and transparent and do not negatively affect NS Power's bundled service customers.

2.0 DISTRIBUTION TARIFF RATE DEVELOPMENT PROCESS

The proposed form of the DT Rates is provided as **Attachment B**. The DT defines the terms, conditions and prices under which eligible distribution-connected RtR Customers can gain access to NS Power's distribution system in the Renewable to Retail Market created under the Act. In the development of the DT, NS Power employed a sequential three step process, used in regulated, cost causative ratemaking, as illustrated in Figure 1.

Figure 1: Overview of the Steps taken in the Development of Distribution Rates



The Company used the most recent Cost of Service Study[3] (COSS) which employed the 2014 Test Year revenue requirement from the 2013 GRA Compliance Filing[4], for the determination of class responsibilities for investments and costs of distribution and retail areas. The COSS is provided as **Attachment C**. The COSS used the following three step process:

- Functionalization of investments and costs by the areas of Distribution and Retail
- Classification of functionalized costs between demand-related and customer-related services
- Allocation of classified costs among the eligible rate classes

The proposed approach to the recovery of distribution and retail costs aligns with those in use in other North American jurisdictions[5].

[3] The Cost of Service Study was filed as part of NS Power's Compliance filing in the Cost of Service proceeding, M05473, July 31, 2014. Please note, several elements of COS were deferred after the Cost of Service Decision for further study and consultation, which may change the total revenue requirement of the Distribution and Retail area and individual class cost responsibilities. Please refer to NS Power 2014 Cost of Service Study Progress Update M06555, Exhibits N-1 and N-2.
[4] 2013 General Rate Application, P-893/M04972, NS Power Compliance Filing, January 16, 2013.
[5] NS Power reviewed Distribution Tariffs from the following utilities: Enmax Power Corporation, EPCOR Utilities Incorporated, ATCO Electric, Milton Hydro Distribution Inc., Appalachian Power Company, Ohio Power Company, Pacific Gas and Electric Company, Southern California Edison.

3.0 DISTRIBUTION AND RETAIL SERVICES

The substantial majority of customers can accept power only at much lower voltage levels of service than that used in transmission.[6] The purpose of the distribution system is, therefore, to connect customers served at a distribution voltage level with the transmission grid.

The Primary Distribution System routes power closer to the majority of customers at moderate voltages in order to minimize electricity losses. Using moderate voltage levels for Primary, while approaching the voltage levels which most customers can accept, reduces amperage and therefore losses. NS Power's Primary Level Distribution System has nominal voltages of 4 kV, 12 kV and 25 kV. There are about 350 customers served at a primary voltage level representing about 20% of the total distribution load. The remaining 80% of the distribution system load enters the secondary voltage lines via distribution line transformers to be delivered to half a million NS Power customers. The assets supporting this last activity consist of Secondary Service conductors and poles and the customers' meters. The majority of NS Power customers take service directly from the distribution transformer low voltage bushings or from secondary lines originating at the transformer.

NS Power segments its investments (rate base) and costs into four functional areas: Generation, Transmission, Distribution, and Retail. The Distribution Tariff applies only costs from the Distribution and Retail areas, not Generation or Transmission. Costs relating to Generation and Transmission are covered in separate tariffs applicable to the Licensed Retail Supplier. The Distribution function is separated into three voltage-differentiated service levels:

- Bulk Power Substations

[6] There are currently ten bundled service transmission-connected customers at NS Power.

- Primary Service (4-25 kV)
- Secondary Service (less than 4 kV).

The Cost of Service (COS) model's functionalization approach also includes a "direct" component that contains rate base and cost elements attributed to street lighting services under the Unmetered Service rate class. General Plant and Property is apportioned among the four functional areas based on their relative shares in the total plant in service. Working Capital is apportioned among the functional areas on the basis of their relative shares in the total plant in service or operational costs already recorded by functional areas. For the purpose of the DT analysis, streetlight assets and costs are kept separate from the remaining distribution rate bases and costs.

The current COSS sub-functionalizes its distribution investment categories in the following manner:

Figure 2: Summary of Distribution Plant in Service by Voltage Service Levels (Thousands of dollars)

DISTRIBUTION PLANT FOR THE YEAR ENDING DECEMBER 31, 2014 (IN THOUSANDS OF DOLLARS)				
	(1)	(2)	(3)	(4)
PLANT	SHARED INVESTMENT BY VOLTAGE-SERVICE LEVELS			TOTAL
	BULK POWER SUBSTATION	PRIMARY	SECONDARY	
LAND	346	2,623	1,465	4,435
EASEMENTS & SURVEY	1,319	9,985	5,578	16,882
OTHER	171	1,295	724	2,190
SUBSTATIONS	26,128	3,985	0	30,113
POLES & FIXTURES		119,005	64,080	183,085
O.H. LINES		78,818	42,441	121,259
U.G. LINES		22,658	12,200	34,858
LINE TRANSFORMERS		0	163,242	163,242
SERVICES		0	60,998	60,998
METERS	21	606	24,445	25,072
STREET LIGHTING (DIRECT)		0	34,507	34,507
TOTAL DIST. PLANT	27,985	238,976	409,680	676,641
GEN. PROPERTY PLANT	2,013	17,193	29,474	48,680
TOTAL BFR WORKING CAPITAL	29,999	256,169	439,153	725,321
WORKING CAPITAL				68,081
TOTAL				793,401

The retail area, under bundled service, includes customer care services such as metering, billing, wiring inspections, responding to customer inquiries, credit services, marketing and sales. The investments associated with COS retail areas such as computer systems, office equipment and general buildings are assigned to other functional areas.

If Retail costs increase or decrease as a result of the introduction of Renewable to Retail, these changes will be reflected in the future DT rates.

4.0 CUSTOMER CLASSES APPLICABLE TO DISTRIBUTION TARIFF SERVICES

4.1 Above the Line Rates

Embedded Cost of Service Studies are conducted for nine retail rate classes and one wholesale class. The retail rate classes include:

- two Residential classes
- three General Service classes
- three Industrial classes
- Unmetered Service class

The two Residential classes, Domestic Service and Domestic Service Time of Day (DTD) are combined into one category for the COSS; however, they are billed under two separate tariffs. The Unmetered rate class includes about 100 published streetlight rates and a few hundred unpublished, customized miscellaneous small load rates designed to meet individual customer needs.

Renewable to Retail service is not applicable to the Wholesale Municipal Class. Wholesale customers[7] are excluded under the Act from being an LRS. There are six wholesale municipal customers served under this class. Four of them are supplied at a distribution voltage level. Since the total COS-based distribution rate base includes these customers, for the DT analysis the distribution rate base must be adjusted to remove rate base costs apportioned to wholesale municipal customers.

[7] Section 2(1)(aaa) of the Act defines a "municipal utility" as "the Board of Commissions of the Berwick Electric Commission, The Electric Light Commissions for Riverport, in the Count of Lunenburg or an electric utility of the Municipality of the District of Guysborough, the Town of Antigonish, the Town of Lunenburg or the Town of Mahone Bay." Section 2(1)(d) of the Act defines a "wholesale customer" as "Nova Scotia Power Incorporated or a municipal utility." Section (2) (1)(c) of the Act specifies that a "wholesale customer" is not a "retail supplier".

There are also seven transmission-connected Large Industrial Customers who are eligible for the Renewable to Retail market but to whom the DT does not apply.

The ten classes above are responsible for all the "above the line" (ATL) rate base and operating expenses of the Company. The summaries of annual usage and costs of these classes are included in COSS Exhibits 9A Annual, 9B, and 10 in Attachment E.

4.2 Below the Line Rates

The Company also provides optional pricing to large customers under formula-based rates. These rates receive accounting treatment outside the COS process, and are deemed to be "below the line" (BTL).[8] If a distribution-connected customer on a BTL rate opts to purchase electricity from a LRS, the corresponding DT rate for the applicable bundled ATL service will apply.

[8] The rates include three 1P-RTP tariffs, Generation Replacement and Load Following, Shore Power Rate and Load Retention Rate.

5.0 REVENUE REQUIREMENT OF DISTRIBUTION AND RETAIL AREAS

The first step in designing the DT rates was to determine the appropriate revenue requirement for the provision of Distribution and Retail Services. From the financial records of the Company, net plant investment is readily identifiable for the Power Production, Transmission, and Distribution functions. Most of the expenses for operations and maintenance for Power Production, Transmission, Distribution and Retail are also readily identifiable. However, there are several components of plant, depreciation and expenses that are not identified by these functional areas. Also, corporate overhead expenses and miscellaneous revenue credits are not tracked by functional areas and must be functionalized in the COSS prior to classification and allocation of costs.

The total distribution and retail revenue requirement of Retail Customers, excluding the capital component of the Light Emitting Diode (LED) fixtures[9] and the distribution-related revenue requirement of the Municipal class, is $238.4 million for 2014.

[9] For the 2012 and 2013 GRAs, the LED fixture costs were proposed to be treated as a BTL item, determined outside of the COSS, due to uncertainty in their estimates ahead of the LED Capital Work Order submission.[NTD LED work order to be filed soon]

Figure 3: Summary of Revenue Requirement of Distribution and Retail Areas (Thousands of dollars)

Revenue Requirement Component	All Distribution Customers	Retail Customers Only		
		Electric Service only	Streetlight Fixtures (non-LED)	Total
Distribution				
Depreciation	56,309	54,191	1,924	56,116
O&M including corporate overhead costs	66,773	60,607	5,825	66,433
Interest, taxes and return on equity	67,093	65,705	1,000	66,705
Miscellaneous Revenue	-2,028	-1,907	0	-1,907
Distribution Total	**188,147**	**178,596**	**8,750**	**187,346**
Retail(1)	**51,358**	**51,088**	**0**	**51,088**
Total	**239,506**	**229,684**	**8,750**	**238,434**

(1) Excludes retail costs of $271,000 of transmission connected Large Industrial and Municipal customers.

Overhead corporate costs assigned to Distribution and Retail, and credits associated with miscellaneous revenues are still being finalized as they were elements of the 2013 Cost of Service proceeding deferred for further study.[10] The overhead costs currently assigned to the Distribution and Retail areas are $43.9 million. The miscellaneous revenues assigned to the Distribution and Retail areas are $10.1 million.

A detailed breakdown of the revenue requirement is included in Exhibits 4, 4 Detail A, and 5 of COSS in **Attachment C**.

[10] Please refer to M05473, Decision 2014 NSUARB 53, pages 44-45.

In its proposed approach, NS Power used the revenue requirement of the Distribution and Retail areas, as predicated on the 2014 Test Year revenue requirement before accounting for a deferral of $83.3 million of fixed costs, which were used to set the current bundled service rates under the two-year Rate Stabilization Plan. The proposed revenue requirement treatment of the DT aligns with that of OATT in the 2013 GRA.

6.0 CLASSIFICATION OF REVENUE REQUIREMENT

NS Power's distribution investments and costs are classified into demand-related and customer-related components.

6.1 Demand-related components

The demand classification is applied to utility assets that are added based upon maximum customer load. Examples of distribution assets classified entirely to demand are substations and line transformers. About two-thirds of total distribution costs and assets are classified to demand.

6.2 Customer-related components

Utilities apply the customer-related classification to equipment necessary to enable a customer to receive service but unrelated to the amount of power consumed. This cost category includes distribution costs which do not vary with customer consumption but may vary directly with the number of customers to be served, such as service drops and meters. Other costs are a fixed requirement necessary for a distribution system regardless of quantity of usage, such as protective devices which operate in the same manner with or without load on the system.

6.3 Components with both customer- and demand-related characteristics

Certain types of distribution equipment cannot be classified as entirely customer-related or demand-related, but instead must be split between the two because the equipment both serves a maximum load requirement (demand) and enables the customer to be connected and thereby capable of receiving service (customer).

Examples of such equipment are distribution poles and distribution line conductors. The first 30% of their rate base and costs are assigned to Primary Service level and classified to demand. The remaining 70 percent is split equally between Primary and Secondary levels. At each level a further equal split occurs between demand- and customer-related costs.

Finally there are supportive assets to the Primary distribution equipment shared among various primary distribution assets and/or other functional areas such as land, general buildings and working capital. The classification of these assets will vary but in most cases is based on the weighted average classification of the most relevant distribution equipment.

Retail expenses are all classified to customer. The classification breakdown of these costs is as follows.

Figure 4: Classification Summary of Revenue Requirement of Distribution and Retail (thousands of dollars)

Functional Area	Demand	Customer	Total
Distribution			
Non-Streetlight Related			
Retail Customers bfr Streetlights	116,708	61,888	178,596
Streetlights	8,750		8,750
Wholesale Customers	798	3	801
Distribution Total	126,255	61,892	188,147
Retail			
Retail Customers		51,182	51,182
Wholesale Customers		176	176
Retail Total		51,358	51,358
Total	126,255	113,250	239,506

The details of classification results of distribution assets are included in Exhibit 2B and those of distribution and retail costs in Exhibit 5 of COSS (**Attachment C)**.

7.0 ALLOCATION OF REVENUE REQUIREMENT

To the extent possible and practical, costs should be assigned to rate classes directly. This can be done when costs are readily identified with a particular customer group or rate class. A direct assignment of costs reflects cost causation and is fair and equitable to customers. The only costs assigned directly in the current COSS are the distribution-related costs of streetlight fixtures and maintenance assigned to the Unmetered Class. Due to the shared nature of NS Power's remaining Distribution and Retail costs, they are apportioned to rate classes based on the relative usage of these resources by rate classes. Demand-related Distribution costs are allocated to rate classes based on each class' share of their total non-coincident demands. Customer-related costs are allocated based on class relative shares of customer count. The breakdown of class demand- and customer-related costs by functional area is provided below.

Figure 5: Summary of Revenue Requirement classification by rate class (Thousands of dollars)

Rate Class	Customers	MWh sales	Distribution Costs			Retail Cost	Total Cost
			Demand	Customer	Total	customer	
Domestic Service	456,991	4,216,538	$68,783	$53,644	$122,428	$42,045	$164,472
Small General	24,109	236,657	$3,878	$2,807	$6,686	$2,498	$9,184
General	11,349	2,448,685	$31,281	$3,804	$35,084	$3,158	$38,242
Large General	19	379,649	$2,394	$8	$2,402	$366	$2,768
Small Industrial	2,221	255,893	$3,122	$744	$3,866	$661	$4,527
Medium Industrial	198	495,412	$4,386	$55	$4,441	$582	$5,023
Large Industrial	25	275,419	$1,303	$14	$1,317	$756	$2,073
Unmetered Service Rates					$0		$0
Electric Service	9,604	98,246	$1,561	$812	$2,372	$1,117	$3,489
Streetlight Maintenance & Capital			$8,750		$8,750		$8,750
Unmetered Total	9,604	98,246	$10,311	$812	$11,122	$1,117	$12,239
Total	504,516	8,406,498	$125,458	$61,888	$187,346	$51,182	$238,528

A detailed classification of class costs by activity is contained in Exhibit 6 of **Attachment C.**

8.0 DETERMINATION OF DISTRIBUTION AND RETAIL USAGE

Rate classes are defined based on discernible customer characteristics (residential, commercial/general, industrial, and other) and size, as delineated by energy consumption and demand criteria (small, medium or large).[11] Implicitly, this segmentation also reflects differentiation by voltage level of service as a practical matter, since larger customers are typically served at higher voltage levels than smaller customers. The usage of these customers is assigned (levelized) in the COS and Load Research Studies at the customer's voltage level of service.

Distribution service costs are allocated to customer classes on the basis of class non-coincident demands and number of customers. For the purpose of determining the demand-based allocation the class demand usage is levelized among three voltage levels: Bulk Power Substation, Primary Voltage and Secondary Voltage. The distribution assets and costs, broken down by these three voltage levels, are then allocated to rate classes based on their relative shares in total class non-coincident demands at these three service levels. NS Power allocates bulk power substation costs based upon Non-Coincident Peak[12] (NCP) rate class demands at the low side of the bulk power transformer. Primary demand-related costs are allocated based upon the NCP rate class demand at primary voltage level. These NCP demands at primary are the combination of secondary NCP demands plus their respective losses and NCP demands for primary customers. Secondary demand-related costs are allocated to rate classes based upon NCP rate class demands at secondary. The non-coincident demand usage by rate classes is provided in Exhibit 9B of **Attachment C**.

[11] Other criteria are used for delineation in some cases. For example, the Domestic Time of Day optional rate is available only to customers with electric heating, a somewhat less immediately discernible feature than residential status itself. Other "niche" rates, such as Unmetered, have special criteria, such as no metering of consumption.

[12] The Non-Coincident Peak Demand of a rate class is measured as the highest hourly energy consumption during a calendar year. It may or may not coincide with class hourly consumption during the hour in which the system peak occurs.

The non-coincident demands of rate classes, other than the Large General, Large Industrial and Municipal classes, are estimated based on the statistical load research sample. The non-coincident demands of all rate classes are also a function of hourly line losses.

The distribution customer-related costs, with the exception of service drops, are apportioned to rate classes based on their relative shares in absolute customer counts. NS Power allocates primary customer-related distribution cost based upon average number of customers at primary and secondary. Secondary customer-related distribution costs are allocated based upon average number of customers at secondary. Service drop costs are currently allocated on the basis of weighted customer counts.

Retail services are allocated to rate classes based on weighted or absolute customer counts modified for the voltage service level, seasonal service, or class membership relevant to the retail activity in question. There are seven customer based allocators. The approach to weighting of customer counts is based on a weighted average of a number of monthly bills and billed revenues in each class per year. The rationale for a weighted customer count is based on recognition that aside from customer number there are other secondary causative factors at work which affect total cost of a retail activity.[13]

[13] As reflected in allocator C-2B in Exhibit 8a of Attachment C, for example, the customer weighting of the Large Industrial customer is 20 times higher than that of the Small Industrial customer. In turn, the weighting of a Small Industrial customer is 5 times higher than that of a Small General customer.

9.0 DISTRIBUTION TARIFF RATE DESIGN

In its design of the DT rates, the Company was guided by the following principles:

- In compliance with s. 3G(2) of the Act, NS Power's remaining customers were not to be negatively affected.
- To the extent practical, leverage existing rates and processes.
- Seek stakeholder consensus.
- Adhere to established ratemaking principles to achieve an appropriate balance among potentially competing ratemaking objectives such as intra-class equitability and simplicity; efficiency and simplicity; and stability and efficiency.

9.1 Rate Classification

In the design of the DT, the Company followed the existing base cost rate classification among the metered and unmetered categories. This approach was chosen for the following reasons:

- The existing COS methodology is well established, following the UARB Decision in the 2013 COS proceeding.[14] It is reflective of cost causation on the distribution system, therefore supportive of the principle of no harm to NS Power's customers.

- Relying on the existing COS methodology makes for easier implementation by leveraging existing ratemaking processes.

- Adherence to the existing COS methodology will be the least disruptive to electric services under the bundled service as this will help avoid artificial pricing

[14] NSPI 2013 Cost of Service Study, UARB Decision, 2014 NSUARB 53, M05473.

incentives to customer migration arising from differences in rate structures between bundled and unbundled rates.

9.2 Revenue to Cost Ratios

To determine revenue responsibilities of bundled service rate classes, NS Power applies an established process, which ensures that the revenue to cost (R/C) ratios for classes fall within the Board-approved 95 to 105 percent band. The process consists of applying first, an across-the-board increase to all classes and then making adjustments to those classes whose ratios fall outside the band. The adjustment is applied at the Board's discretion to provide a more stable rate environment to customers by minimizing fluctuations in rates attributable to imperfections in the COSS as well as uneven cost pressures on rate classes in GRA proceedings.

The Company is proposing that the DT rates be set directly at cost, without R/C adjustments, for the following reasons:

1. Setting DT rates strictly at cost of service aligns with the ratemaking treatment under the OATT, which allows for a consistent treatment of all delivery charges applicable to open access distribution customers.

2. With generation and transmission rates of open access distribution customers being already exempted from the R/C ratio adjustment there is less compelling reason, from a rate stability perspective, to apply such an adjustment solely to distribution rates which represent about a quarter of the total cost of electricity.

3. The R/C ratios used for the bundled rates are reflective of broad cost considerations accounting for all four functional cost areas. There is no conceptual basis for transferring these ratios to a small portion of bundled service revenue requirement associated with distribution and retail costs.

4. Strictly cost of service based DT rates allow for a more transparent rate setting process.

9.3 Rate Structure for Metered Services

In the design of the distribution rate structures, the Company sought to find the right balance among simplicity, efficiency and intra-class equity as affected by pricing signals embedded in rates. To deliver on the objective of designing efficient and equitable rates the Company endeavored to align, to the extent practical, the rate structures of DT with classification of class costs by demand-related and customer-related components. A comparison of the proposed DT class rate structures to their bundled service counterparts is set out in **Attachment D**.

9.3.1 Customers on Energy and Customer charges

The Company proposes to retain the current rate structure for the two Domestic and Small General rate classes with the following exceptions:

- The time-differentiated energy charge components of the Domestic Time of Day (TOD) rate are proposed to be replaced with one distribution usage charge component. The distribution usage charge component is proposed to be the same for the two Domestic rate classes.

- The declining block rate structure of the Small General class is proposed to be replaced with the one distribution usage charge component.

The customer charges under the two Domestic and Small General rate classes were retained at their current levels. The charges currently recover about two-thirds of the COSS-based customer-related costs representing about 10% of the total bundled service class costs. The current level of these charges is reflective of historical rate design practices including the UARB Decision in the 2003 Generic Rate Design Hearing[15] which effectively froze these charges. In order to not create an artificial incentive or disincentive for customers to move to alternate service providers, due to a difference in rate structures, the Company retained customer charges at their current level.

The energy charges under these rates are designed to recover both energy and demand-related costs. Given the small loads of these customers and their general inability to respond to price signals embedded in demand charges, installation of more expensive demand meters would not be warranted. The Company proposes, therefore, that the energy charges in cents per kWh continue to be used as a proxy for the recovery of demand-related distribution costs.

Domestic Time of Day rates

The purpose of the current TOD rate structure is to recognize the generation-related cost savings to NS Power from load shifting using the electric thermal storage (ETS) equipment-control under the bundled service. The higher customer charge of $18.82 per month for TOD Domestic Service, compared to $10.83 for Domestic Service, under the bundled services, is reflective of higher TOD meter costs and an additional charge to make up for lost revenue due to introduction of reduced rates for the afternoon shoulder period in the winter months of January, February and December[16].

There is no time-differentiated cost causation effect present in the bundled TOD rate for recovery of distribution and retail costs. Therefore, application of a flat distribution usage charge is appropriate to TOD customers who will retain the TOD meters. The

[15] NSUARB-NSPI-P-878, NSPI Generic Rate Design Hearing, Matter Number M05002, Decision 2003 NSUARB 91, August 1, 2003, pages 47-48

[16] NS Power 1995 Rate Hearing, UARB Decision, M06131, March 4, 1996, page 68.

customer charge is proposed to be reduced by $5.67 to $13.15 to reflect the retail and distribution costs and TOD meter costs included in the TOD customer charge.

Customers who no longer require TOD meters will have them replaced with non-TOD meters and will be billed under the Domestic Service rate.

Small General Class

The Company proposes to recover distribution costs of the Small General class through a flat distribution charge in cents per kWh instead of the two declining block charges. This approach allows for a simpler rate design which aligns customer treatment between the Small General and Residential rate classes.[17]

9.3.2 Customers on Demand charges

The Company proposes that all demand-related distribution costs of customers currently billed under the bundled rates with demand charges be recovered through demand charges. In addition, as is the case with the bundled service rates, it is also being proposed that all customer-related costs be recovered through the demand charges. Since there are no energy-related costs in the distribution and retail areas, there is no need to retain distribution usage charges in cents per kWh for these customers.

Rates with demand charges do not include customer charges. Customer-related costs represent only a very small portion of the total cost of power of these customers, who are

[17] Since the time of the design of its declining block structure, which predates the generic cost of service and rate design proceedings conducted in 1993, the availability criterion under the rate has increased from usage less than 12 MWh per year to 45 MWh per year. This change was justified, among other things, on the basis of similarity in usage profiles between the residential and small general customers consistent with the ratemaking concept of "like rates for like service".

much bigger consumers than customers billed under the energy only rates.[18] In order to keep the rate structures of these classes as simple as possible, the customer-related costs are currently recovered through the rate components of energy in cents per kWh and demand in dollars per kW or kVA. NS Power proposes that this practice continue under the rate design of the DT.

9.3.3 Proof of Revenue

The rates for each metered service are determined by dividing their revenue requirements associated with services provided under the rate component by their respective billing determinant. Please refer to **Attachment E** for the Proof of Revenue calculations behind the rate components applicable to metered services under the DT.

9.4 Unmetered Rates

The Company proposes that its ratemaking approach for the determination of Unmetered Streetlight and Small Miscellaneous Loads rates be applied in the design of DT rates for these customers. This will result in the same types and number of rates as provided under bundled service.

The DT streetlight rates are proposed to be offered under the three distinct service categories for non-LED types of fixtures:

1. Electric service only, applicable to both streetlight and miscellaneous loads;

2. Electric service combined with streetlight fixture maintenance; and

[18] The customer-related costs account from 1 percent to 2 percent of the total costs of the rate classes on demand charges.

3. Full streetlight service, which includes electric service, maintenance and capital costs associated with streetlight fixtures.

In addition the DT will accommodate two types of LED services:

1. Electric service only, applicable to both streetlight and miscellaneous loads; and

2. Full streetlight service, which includes electric service, maintenance and capital costs associated with streetlight fixtures.

10.0 CONCLUSION

The proposed approach to the design of the DT rates leverages existing rate structures and cost of service methodology. It is grounded in established ratemaking principles and, as such, provides a cost neutral rate framework that will support development of the Renewable to Retail market. The proposed distribution rate structures, by their alignment with their bundled service counterparts, make for easy implementation and fair allocation of costs among customers. They also provide unbiased pricing signals that will enable rational generation service choice decisions.

NOVA SCOTIA POWER INCORPORATED

DISTRIBUTION TARIFF

As Approved by the UARB on ●

DRAFT

May 21, 2015 – Version 1

SUBJECT TO NS POWER MANGEMENT REVIEW & APPROVAL

Nova Scotia Power Distribution Tariff

TABLE OF CONTENTS

Contents

1. DEFINITIONS

In this Distribution Tariff, the following terms shall have the following meanings:

Act: The *Electricity Act*, S.N.S. 2004, c. 25, as amended from time to time.

Ancillary Services: Services that are necessary to support the transport of capacity and energy from generation resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

Board: The Nova Scotia Utility and Review Board.

Demand Side Management (DSM) Recovery Charges: Costs of demand side management programs that NS Power is entitled to recover from RtR Customers.

Distribution System: NS Power's facilities and equipment (generally rated at less than 69 kV) used to distribute electricity to ultimate usage points such as homes and industries either directly from nearby generators or from interchanges from the Transmission System.

Distribution System Access: The services provided by NS Power to the RtR Customer under the Distribution Tariff to provide for the connection of the RtR Customer to the Distribution System for the purpose of receiving renewable low-impact electricity purchased from a LRS to RtR Customers, but does not include the provision of electricity. These services are comprised of delivery of electricity on the distribution system and related services including connections, disconnections, line and service extensions, inspection services, meter services, power restoration, meter reading, and customer service, all in accordance with applicable NS Power Regulations.

Distribution Tariff Rate Schedules: The rate schedules attached hereto as Appendix A which outline the pricing and availability provisions for Distribution System Access.

Distribution Tariff: This Distribution Tariff, its terms and conditions and all appendices and attachments referenced herein, including the Distribution Tariff Rate Schedules.

Good Utility Practice: Those practices, methods or acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America) that at a particular time, in the exercise of reasonable judgment, would have been expected to accomplish the desired result in a manner consistent with regulations, reliability, safety, environmental protection, economy and expedition as applied and practiced in the utility industry with respect to power generation, delivery, purchase and sale.

Licensed Retail Supplier (LRS): A person who:

(a) is authorized to sell renewable low-impact electricity, generated within the Province, in accordance with the Act and the regulations made thereunder but does not include a Wholesale Customer; and

(b) has been issued a Retail Supplier License by the Board.

For certainty, a Wholesale Customer is not an LRS for the purposes of this Distribution Tariff.

NS Power: Nova Scotia Power Incorporated.

NS Power Regulations: NS Power Regulations approved by the Board pursuant to the *Public Utilities Act* (Nova Scotia) as such regulations may be amended from time to time with the approval of the Board.

OATT: Open Access Transmission Tariff

Province: Province of Nova Scotia

Real Power Losses: Resistive losses occurring as the result of current flow through primary distribution feeders, distribution transformers, secondary conductors and service drops.

Renewable low-impact electricity: Electricity that meets the definition of "renewable low-impact electricity" as defined under the Renewable Electricity Regulations (Nova Scotia).

RtR Customer: A Retail Customer who is a customer of an LRS for the supply of renewable low-impact electricity.

Retail Customer: A person who (a) uses, for the person's own consumption in the Province, renewable low impact electricity that the person did not generate; and (b) is authorized under the Act to purchase renewable low-impact electricity, generated within the Province from an LRS. For greater certainty, a customer of a municipal utility (as defined under the Act) is not a Retail Customer for the purposes of this Distribution Tariff.

Retail Supplier License: The retail supplier license issued by the Board in accordance with the Act and Regulations made thereunder which authorizes a person to sell renewable low-impact electricity generated within the Province to an RtR Customer.

RtR Customer Transaction Request Application: A NS Power document to be used by a Licensed Retail Supplier for the purpose of applying to NS Power to accept and process RtR Customer transactions.

Transmission Provider: NS Power.

Transmission Services: The services obtained by market participants under the terms and conditions of the OATT to access the Transmission System for the purpose of transporting electric energy and Ancillary Services.

Transmission System: The facilities, generally rated at 69 kV and above, owned, controlled or operated by the Transmission Provider that are used to provide transmission service under the OATT.

Wholesale Customer: NS Power or a municipal utility (as defined under the Act).

2. PURPOSE OF THE DISTRIBUTION TARIFF

In accordance with the provisions of the Act and the regulations made thereunder (Regulations), NS Power will, through the terms of this Distribution Tariff, provide Distribution System Access to RtR Customers for the purposes of receiving renewable low-impact electricity from a Licensed Retail Supplier.

3. SCOPE OF THE DISTRIBUTION TARIFF

The Distribution Tariff is applicable to RtR Customers connected to the Distribution System. This Distribution Tariff is not applicable to RtR Customers directly connected to the Transmission System. Transmission-connected RtR Customers must have their Transmission System access arranged by the LRS under the provisions of the OATT.

The Distribution Tariff outlines the rules, terms and conditions that apply to the provision of Distribution System Access to RtR Customers.

The Distribution Tariff Rate Schedules applicable to the provision of Distribution System Access are attached to this Distribution Tariff as Appendix A.

4. BOARD APPROVAL

The Distribution Tariff has been approved by the Board.

Nothing contained in the Distribution Tariff shall be construed as affecting in any way the right of NS Power to unilaterally make application to the Board for a change in any rates (including the Distribution Tariff rates set out in Appendix A), terms and conditions, charges, classification of service, rules or regulations.

5. APPENDICES

For greater certainty, Appendix A attached hereto forms part of the Distribution Tariff.

6. APPLICABILITY OF NS POWER REGULATIONS TO THE RTR CUSTOMER

The NS Power Regulations apply to an RtR Customer receiving Distribution System Access under this Distribution Tariff.

7. NS POWER RESPONSIBILITIES

NS Power shall be responsible for:

(a) provision of Distribution System Access to RtR Customers.

(b) processing RtR Customer Transaction Request Applications that are received from an LRS on behalf of the RtR Customer; and

(c) providing billing data for the RtR Customer's Distribution Tariff charges for inclusion on the RtR Customer's invoice.

NS Power shall not be responsible for the supply of electricity (whether renewable low-impact electricity or otherwise) which the RtR Customer shall be obligated to obtain from an LRS.

NS Power shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements between the RtR and the LRS and shall not be liable for any loss, damages, cost, injury, expense or other liability, whether direct, indirect, consequential or special in nature, howsoever caused, as a result of the LRS's failure to perform its obligations to its RtR Customer(s).

The LRS shall at all times indemnify, defend, and save NS Power, its officers, directors and affiliates, harmless from, any and all damages, losses, claims arising from the RtR Customer's failure to perform any of the RtR Customer's obligations to the LRS.

8. RtR CUSTOMER RESPONSIBILITIES

As the receiver of Distribution System Access, the RtR Customer shall be responsible for:

(a) payment of all invoices arising from the Distribution Tariff;

(b) compliance with the terms and conditions of the Distribution Tariff and the NS Power Regulations;

(c) obtaining a supply of renewable low-impact electricity; and

(d) all contractual arrangements with an LRS for the supply of renewable low-impact electricity.

9. INTERRUPTION OF DISTRIBUTION SYSTEM ACCESS

NS Power shall have no liability to the RtR Customer for any loss or damage arising, either directly or indirectly, from any failure in the provision of Distribution System Access, under the terms of this Distribution Tariff, in respect of any abnormality, delay, interruption or other partial or complete failure in the said provision of Distribution System Access when such loss or damages are caused by something that is beyond the ability of NS Power to control by reasonable and practicable effort, said effort to be measured by Good Utility Practice.

Notwithstanding any term of this Distribution Tariff, NS Power shall have the right to suspend the provision of Distribution System Access for the purpose of safeguarding life or property, for making repairs, changes, renewals, improvements or replacements to the Distribution System provided NS Power shall make commercially reasonable efforts to ensure all such interruptions are of a minimum duration consistent with the exigencies of the case, provided, however, any such interruptions shall not release the RtR Customer from its obligation to pay all charges pursuant to this Distribution Tariff during the period of any such suspensions and to resume the use of power and energy when the supply is restored.

The RtR Customer shall be responsible for any additional costs incurred by NS Power resulting from performance of repairs, changes, renewals, improvements or replacements outside of normal working hours, at the RtR Customer’s request.

10. METERING

10.1. Provision and Ownership

NS Power will provide, install and seal all revenue class meters for the purpose of measuring the RtR Customer's load. The meters will be used for determining charges under the Distribution Tariff applicable to the RtR Customers.

Interval meters with remote polling capability shall be installed for all RtR Customers. NS Power will charge the costs of the supply and installation of metering devices and communications equipment and services which are incremental to the metering requirements applicable to NS Power's bundled service.

All Meters and associated revenue metering equipment shall remain the property of NS Power.

RtR Customer metering requirements are set out in the NS Power Regulations Section 4 - Metering.

10.2. Meter Reading

RtR Customer meter reading requirements are set out in NS Power Regulations Section 5 – Meter Reading and Billing.

11. BILLING

11.1. Billing

The Distribution Tariff amounts payable by the RtR Customer will be calculated by NS Power using the RtR Customer's meter readings and the Distribution Tariff Rate Schedule applicable to the RtR Customer's rate class.

NS Power may authorize the LRS to invoice the LRS' RtR Customer for any charges or fees, inclusive of all applicable taxes, owing by the RtR Customer to NS Power (NS Power Charges) under this Distribution Tariff and to consolidate such charges and fees on the LRS' invoice to the RtR Customer.

In the event NS Power authorizes and LRS to invoice the RtR Customer, the NS Power Charges will be invoiced to the LRS by NS Power, passed through to the RtR Customer by the LRS, and identified on the RtR Customer's invoice from the LRS as NS Power Distribution Tariff charges.

In the absence of a consolidated billing arrangement between NS Power and the LRS, NS Power shall invoice the RtR Customer directly for the NS Power Charges.

The NS Power Charges shall include:

(a) Distribution System Access;

(b) Demand Side Management Recovery Charges; and [NTD: to be determined]

(c) Other items as may be approved by the Board.

NS Power may, at its discretion, include fees for any special customer services, pursuant to NS Power Regulation 7.1 - Schedule of Charges.

11.2. Application of Distribution Tariff Rates

NS Power shall determine the amounts payable by the RtR Customer by applying the Distribution Tariff Rate Schedules in Appendix A applicable to the RtR Customer's load as metered.

If the operational or consumption characteristics of the RtR Customer change, such that the RtR Customer, in NS Power's determination, no longer qualifies for its current rate class, NS Power shall apply a Distribution Tariff rate appropriate to the RtR Customer's new operational or consumption characteristics.

11.3. Real Power Losses

Distribution System Real Power Losses associated with Distribution System Access are incorporated in the Distribution Tariff rates applicable to each RtR Customer's rate class. The RtR Customer is responsible for the costs of such Real Power Losses.

12. DISCONTINUANCE OF DISTRIBUTION SYSTEM ACCESS BY NS POWER

NS Power may discontinue Distribution System Access to an RtR Customer in accordance with the requirements of NS Power Regulations Section 6 – Collection of Accounts, Regulations 6.1 - Disconnection of Electric Service, 6.2 - Rules Governing Disconnection and 6.3 - Medical Emergency.

APPENDIX A: DISTRIBUTION TARIFF RATE SCHEDULES

DRAFT – subject to NS Power management review and approval **May 21, 2015**

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

Note: For certainty, all capitalized terms shall, unless otherwise defined herein, have the meanings ascribed thereto in Distribution Tariff.

APPLICABILITY

This schedule provides charges for Distribution System Access applicable to distribution-connected RtR Customers, receiving supply of renewable low-impact electricity from a Licensed Retail Supplier as provided for under the Electricity Act (Nova Scotia).

CHARGES

Rate Class	Customer Charge $/month	Distribution Charge ¢/kWh	Demand Charge $/kVa	Minimum Monthly Charge $/month	Transformer Ownership Credit $/kVa
Domestic Service	10.83	2.541	0.000	10.83	0
Domestic Service Time of Day	13.15	2.541	0.000	13.15	0
Small General	12.65	2.362	0.000	12.65	0
General	0	0.000	5.458	12.65	-0.32
Large General	0	0.000	3.361	12.65	-0.32
Small Industrial	0	0.000	4.494	12.65	-0.32
Medium Industrial	0	0.000	3.496	12.65	-0.32
Large Industrial Firm	0	0.000	2.430	12.65	-0.32
Large Industrial Interruptible	0	0.000	2.430	12.65	-0.32
Outdoor Recreational Light Rate	0	3.551	0.000	0	0
Unmetered Service Rates	0	0.000	11.960	17.51	0
Miscellaneous Small Loads	0	0.000	11.960	17.51	0

Footnotes

(1) Demand Charges and credits are applicable to kW demand.
(2) Demand Charges and credits are applicable to kilovolt-ampere of maximum demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven months regardless whether service was taken under the bundled or unbundled service.

PROPOSED: EFFECTIVE:

DRAFT – subject to NS Power management review and approval **May 21, 2015**

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The same maximum per kWh charges and minimum bills will apply as stated in tariffs for bundled service.

AVAILABILITY

The same Availability conditions will apply as stated in tariffs for bundled service.

SPECIAL CONDITIONS

The same Special Conditions will apply as stated in tariffs for bundled service.

PROPOSED: EFFECTIVE:

DRAFT – subject to NS Power management review and approval **May 21, 2015**

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(A) **STREET AND AREA LIGHTING**

RATES

(1) **INCANDESCENT**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
001	300 and less	97	$10.78	
002	Greater than 300	154	13.09	
b) Operating Only				
003	300 and Less	97	3.74	

(2) **MERCURY VAPOUR**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
100	100	43	$10.03	
101	125	52	11.88	
102	175	69	10.77	
103	250	97	12.59	
104	400	154	14.86	
105	700	260	20.14	
106	1000	363	25.15	
107	250	212	17.74	Continuous Operation
b) Operating and Maintenance Only				
201	125	52	$8.87	
202	175	69	7.80	
203	250	97	8.90	
204	400	154	11.09	
205	700	260	15.19	
206	1000	363	19.17	

c) Operating Only

PROPOSED: EFFECTIVE:

DRAFT – subject to NS Power management review and approval **May 21, 2015**

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

301	125	52	$2.00
302	175	69	2.64
303	250	97	3.74
304	400	154	5.93
305	700	260	10.03
306	1000	363	14.01

(3) **FLUORESCENT**

Rate Code	**Bulb Length**	**Number of Bulbs/Unit**	**kWh/Mo.**	**$/Mo.**	**Other**
a)	Operating, Maintenance and Capital (Full Charge)				
110	24	2	30	13.91	
111	48	2	85	16.28	
112	72	2	116	17.96	
113	72	4	222	23.16	
114	96	1	47	15.08	
115	72	1	60	15.21	
116	48	4	166	19.99	
b)	Operating and Maintenance Only				
213	72	4	222	$18.86	
214	96	1	47	12.11	
215	72	1	60	12.63	
216	48	4	166	16.74	
217	48	1	49	12.18	
218	48	2	85	13.59	
c)	Operating Only				
330	35	4	47	1.80	

PROPOSED: EFFECTIVE:

DRAFT – subject to NS Power management review and approval **May 21, 2015**

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(4) **FLUORESCENT CROSSWALK**

a) Continuous Burning - Operating Only

117	72	4	486	$8.56
118	24	2	66	1.15
119	48	4	364	6.43
120	96	2	254	4.49
150	96	4	613	10.80

PROPOSED: EFFECTIVE:

DRAFT – subject to NS Power management review and approval **May 21, 2015**

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(4) **FLUORESCENT CROSSWALK (cont.)**

b) Photocell Operation - Operating Only

310	24	2	30	$1.17
311	48	4	166	6.43
312	72	2	116	4.50
313	72	4	222	8.55
314	96	1	47	1.80
315	72	1	60	2.32
350	96	4	280	10.82

(5) **LOW PRESSURE SODIUM**

Rate Code	**Watts**	**kWh/Mo.**	**$/Mo.**	**Other**
a) Operating, Maintenance and Capital (Full Charge)				
130	135	60	$23.58	
131	180	80	26.94	
132	90	45	22.99	
b) Operating and Maintenance Only				
231	180	80	18.56	
c) Operating Only				
331	180	80	3.09	

(6) **HIGH PRESSURE SODIUM**

a) Operating, Maintenance and Capital (Full Charge)

121	250	100	$12.23	
122	400	150	14.28	
123	70	32	9.41	
124	100	45	9.93	
125	150	65	10.89	
126	100	99	15.08	Continuous Operation

PROPOSED: EFFECTIVE:

DRAFT – subject to NS Power management review and approval **May 21, 2015**

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(6) **HIGH PRESSURE SODIUM (**cont'd)

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
b) Operating and Maintenance Only				
221	250	100	$9.02	
222	70	32	6.39	
223	100	45	6.89	
224	150	65	7.67	
c) Operating Only				
321	250	100	$3.86	
322	70	32	1.23	
323	100	45	1.73	
324	150	65	2.51	
326	400	150	5.79	
327	500	183	7.07	
328	1000	363	14.02	
329	1500	500	19.30	

(7) **METALLIC ADDITIVE**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
140	400	150	$17.85	
141	1000	360	31.83	
142	250	100	19.98	
143	150	67	18.70	
144	100	50	18.05	
b) Operating Only				
341	1000	360	$13.89	
342	400	150	5.79	
343	250	100	3.86	
344	175	75	2.89	
345	150	67	2.58	
346	100	50	1.93	

PROPOSED: EFFECTIVE:

DRAFT – subject to NS Power management review and approval **May 21, 2015**

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(8) **LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY**

Rate Code	$/Mo.	Other
530	$0.06	Non – Continuous
531	$0.09	Continuous

(9) **LIGHT EMITTING DIODE (LED) – Operating Only**

Rate Code	Watts	kWh/Mo.	$/Mo.
532	44	15	$0.58
533	66	22	0.85
534	88	29	1.12
535	92	31	1.20
536	105	35	1.35
537	170	57	2.20
539	110	37	1.43
540	65	22	0.85
541	55	18	0.69
542	83	28	1.08
543	48	16	0.62
544	72	24	0.93

(10) **INTERIM LIGHT EMITTING DIODE (LED) – Operating & Capital Only***

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
615	44	15	$7.85	
616	55	18	7.96	
623	28	9	7.62	
624	50	17	7.93	
625	72	24	8.20	
626	100	33	8.54	
627	200	67	9.86	

* While fixture maintenance costs associated with LED streetlights may occur, this component is currently not reflected in the rates.

PROPOSED: EFFECTIVE:

PROPOSED DISTRIBUTION TARIFF AS BASED ON 2014 COSS

Draft - Dubject to NS Power management review and approval 21-May-15

RESIDENTIAL TARIFFS

Domestic Service Rate		**units**	**Current Bundled Rate**	**Proposed Distribution Rate**	**% change**
Customer Charge		$/mo	10.830	10.830	0.0%
Energy Charge		¢/kWh	14.251	2.541	-82.2%
Domestic Service TOD Rate					
Customer Charge		$/mo	18.820	13.150	-30.1%
December, January & Feb: energy charge					
	on-peak	¢/kWh	18.609	2.541	-86.3%
	shoulder	¢/kWh	14.251	2.541	-82.2%
	off-peak	¢/kWh	7.324	2.541	-65.3%
Other months: energy charge					
	on-peak	¢/kWh	14.251	2.541	-82.2%
	off-peak	¢/kWh	7.324	2.541	-65.3%

COMMERCIAL TARIFFS

Small General Rate	**units**	**Current Bundled Rate**	**Proposed Distribution Rate**	**% change**
Customer Charge	$/mo	12.650	12.650	0.0%
Energy Charge, block 1 (first 200 kWhs)	¢/kWh	15.092	2.362	-84.3%
Energy Charge, block 2	¢/kWh	13.278	2.362	-82.2%
General Rate				
Demand Charge	$/kW	10.497	5.458	-48.0%
Energy Charge, block 1 (first 200kWh * demand)	¢/kWh	11.208	-	-100.0%
Energy Charge, block 2	¢/kWh	7.929	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Large General Rate				
Demand Charge (Ratcheted)	$/kVA	13.345	3.361	-74.8%
Energy Charge	¢/kWh	8.029	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%

INDUSTRIAL TARIFFS

Small Industrial Rate	**units**	**Current Bundled Rate**	**Proposed Distribution Rate**	**% change**
Demand Charge	$/kVA	7.714	4.494	-41.7%
Energy Charge, block 1 (first 200 kWhs * demand)	¢/kWh	10.090	-	-100.0%
Energy Charge, block 2	¢/kWh	7.707	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Medium Industrial Rate				
Demand Charge	$/kVA	12.501	3.496	-72.0%
Energy Charge	¢/kWh	7.241	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%

Large Industrial Rate				
Demand Charge (Ratcheted)	$/kVA	11.995	2.430	-79.7%
Energy Charge to firm Customers	¢/kWh	7.620	-	-100.0%
Energy Charge to interruptible customers		7.222	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Interruptible Credit	$/kVA	(3.430)	(3.430)	0.0%

OTHER TARIFFS

Outdoor Recreational Light Rate	**units**	**Current Bundled Rate**	**Proposed Distribution Rate**	**% change**
Energy Charge	¢/kWh	14.354	3.551	-75.3%
Miscellaneous Small Loads Rate				
Demand Charge	$/kW	11.777	11.960	1.55%
Energy Charge, block 1 (first 200kWh * demand)	¢/kWh	13.467	-	-100.00%
Energy Charge, block 2	¢/kWh	8.941	-	-100.00%

May 21, 2015 DISTRIBUTION TARIFF PROOF OF REVENUE Attachment E

Proposed Distribution Tariffs	Distribution Usage in KWhs			Demand in kWs or kVa			Base Charge			PROPOSED
	Energy in GWh	Per KWh Charge	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	RATES FORECAST 2014
Above-the-line Classes	-									
Residential Sector										
Non-ETS	3,993.3	$ 0.02541	$ 101.5	NA	NA	NA	5.1	$ 10.83	$ 55.4	$ 156.8
ETS	223.2	$ 0.02541	$ 5.7	NA	NA	NA	0.1	$ 13.15	$ 2.0	$ 7.6
Total	**4,216.5**		**$ 107.1**	**NA**	**NA**	**NA**	**5.3**		**$ 57.33**	**$ 164.5**
Commercial Sector										
Small General	236.7	$ 0.02362	$ 5.6	-		$ -	0.3	$ 12.65	$ 3.6	$ 9.2
General Demand	2,448.7	NA	NA	7.0	$ 5.458	$ 38.2	-	$ -	$ -	$ 38.2
Large General										
Without Trans. Own.	245.8	NA	NA	0.5	$ 3.361	$ 1.7				$ 1.7
With Trans. Own.	133.8	NA	NA	0.3	$ 3.041	$ 1.0				$ 1.0
Sub-total	379.6	NA	NA	0.9		$ 2.8				$ 2.8
Total	**3,065.0**		**$ 5.6**	**7.9**		**$ 41.0**	**0.3**		**$ 3.6**	**$ 50.2**
Industrial Sector										
Small Industrial	255.9	NA	NA	1.0	$ 4.494	$ 4.5				$ 4.5
Medium Industrial	495.4	NA	NA	1.4	$ 3.496	$ 5.0				$ 5.0
Large Industrial Firm		NA	NA							
Without Trans. Own.	46.3	NA	NA	0.1	$ 2.430	$ 0.3				$ 0.3
With Trans. Own.	-	NA	NA	-	$ 2.110	$ -				$ -
Sub-total	46.3	NA	NA	0.1		$ 0.3				$ 0.3
Large Industrial Interr.										
Without Trans. Own.	176.4	NA	NA	0.5	$ 2.430	1.2				$ 1.2
With Trans. Own.	52.8	NA	NA	0.3	$ 2.110	0.6				$ 0.6
Sub-total	229.1	NA	NA	0.8		1.8				$ 1.8
Total Large Industrial	**275.4**	**NA**	**NA**	**0.89**		**$ 2.1**				**$ 2.1**
Total Industrial	**1,026.7**	**NA**	**NA**	**3.3**		**$ 11.6**	**0.0**		**0.0**	**$ 11.6**
Other										
Unmetered[1,2]										
Electric Service Only	98.2	$ 0.03551	$ 3.5							$ 3.5
Street ligth Fixtures										$ 8.8
Total										$ 12.2
Total Above-the-line	**8,406.5**		**$ 116.2**	**11.2**		**$ 52.6**	**5.5**		**$ 60.9**	**$ 238.5**

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights

(2) Per kWh charge is not applicable as the class is made up of a number of rates

Appendix 11A has been provided in electronic format only.

ENERGY BALANCING SERVICE

The Renewable to Retail ("RtR") Energy Balancing Service is a supplemental generation service provided to Licensed Retail Suppliers (LRS) in respect of their RtR customers utilizing the production from low impact, renewable generators. The service consists of delivery of complementary energy to customers and reception of surplus generation from qualifying generators. The service is required to be complemented by Standby Service so that the reliability of service to RtR customers is equivalent to that provided under bundled service. For the purposes of this tariff, hourly LRS load in excess of generation is defined as top-up energy and hourly generation in excess of LRS load is defined as spill energy.

AVAILABILITY

The tariff is applicable to the LRS to facilitate the purchase of renewable low-impact electricity by RtR customers.

The tariff is provided under the following terms and conditions:

(1) The LRS has executed an LRS Participation Agreement which remains in effect.

(2) The LRS is providing service to RtR customers.

APPLICABILITY

(1) An LRS taking service under this tariff must also take service under the Open Access Transmission Tariff (OATT) and the Standby Service tariff.

(2) The service under this tariff is based on metered energy quantities, and is independent of the LRS's forecasts. OATT Schedule 4 is not applicable, but the Forecasting deviation service under Schedule 4A of the OATT is applicable.

(3) The hourly top-up and spill quantities are determined at the delivery point from the transmission system. The hourly top-up quantity equals the excess in each hour, if positive, of the LRS's aggregate customer load adjusted by the addition of distribution losses over the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission losses. The hourly spill quantity equals the excess in each hour, if positive, of the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission losses over its aggregate customer load adjusted by the addition of distribution losses. Hourly load includes load in respect of firm and interruptible supply customers. The aggregate hourly load quantities are determined in accordance with Section 13 of the LRS Terms and Conditions.

(4) To qualify for this service, the LRS must ensure that low impact renewable generation

meets the kWh energy needs of its customers on an annual basis. This requires that top-up energy not exceed spill energy on an annual basis.

(5) Maximum Spill Capacity must be approved by Nova Scotia Power Inc. (NS Power or the Company) prior to commencement of service and will be limited to a level agreed as being required to provide the contracted annual amount of participating LRS energy. Spill capacity will be reviewed annually and will include the LRS' proposal to mitigate it on a going forward basis. If the Company is not satisfied with the LRS' proposal, it may impose a limit on hourly production of the LRS's generation portfolio.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS's subscribed} * 12}$$

This charge will be $1,053.03 per month.

ENERGY CHARGE

Energy charge for top-up service is made up of the following two components:

1. Annually adjusted fuel cost component based on the Company's incremental cost of serving the LRS's forecasted incremental top-up load.

2. Fixed cost adder reflective of fixed cost energy-related generation costs.

Energy Charge Components	Cents per kWh
Fuel Cost	6.650
Fixed Cost Adder	3.451
Total	10.101

The charge is applicable to top-up energy consumed in each hour.

ENERGY CREDIT

The Energy Credit for spill service is set annually, on a calendar year basis, and is made up of two

Note: Rates shown are indicative and conditional on the Board's approval.

components:

1. Monthly compensation for spill energy delivered to NS Power and applicable in each hour of 5.27 cents per kilowatt hour

2. The year-end refund to the Company on monthly compensation in respect of annual excess spill energy above annual consumption of the LRS's RtR customers recognized without discount as set out in the following table:

Annual Excess Spill Quantity in the range	**Discount Applied**	**Cents per kWh**
from 0% to 10% of Annual LRS Load	0%	5.270
greater than 10% up to 20% of Annual LRS Load	10%	4.743
greater than 20% up to 30% of Annual LRS Load	25%	3.953
greater than 30% of Annual LRS Load	50%	2.635

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge

SPECIAL CONDITIONS

(1) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(2) The LRS's retail customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

Note: Rates shown are indicative and conditional on the Board's approval.

(4) Nothing contained in this Energy Balancing Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to unilaterally make application to the Nova Scotia Utility and Review Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Energy Balancing Service Tariff.

STANDBY SERVICE

Renewable to Retail ("RtR") Standby Service is a supplemental generation capacity service provided to Licensed Retail Suppliers (LRS). The service is provided in combination with Energy Balancing Service. The service has two components:

> **Capacity adequacy service –** fulfillment of the LRS's obligation to provide or pay for its share of firm capacity required to meet adequacy standards of the Nova Scotia electricity system arising from forced and unforced generation outages. Energy delivered during generation outages will be billed under the Energy Balancing Service Tariff.
>
> **Top-up capacity service** – provision of capacity to support energy delivery through the Energy Balancing Service in respect of imbalance between load and generation.

AVAILABILITY

The tariff is applicable to the LRS to facilitate the purchase of renewable low-impact electricity by RtR customers.

The tariff is provided under the following terms and conditions:

(1) The LRS has executed an LRS Participation Agreement which remains in effect.

(2) The LRS is providing service to RtR customers.

APPLICABILITY

(1) An LRS taking service under this tariff must also take service under Open Access Transmission Tariff (OATT) and the Energy Balancing Service Tariff.

(2) The service under this Tariff is complementary to the generation ancillary services to the RtR Market under OATT.

(3) The aggregate hourly load quantities are determined at the delivery point from the transmission system, inclusive of distribution system losses, in accordance with Section 13 of the LRS Terms and Conditions.

(4) Interruptible retail customers of the LRS will be subject to the same interruptible service conditions as under the otherwise applicable bundled service tariff.

Note: Rates shown are indicative and conditional on the Board's approval.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS's subscribed} * 12}$$

This charge will be $1,053.03 per month.

DEMAND CHARGE

$5.370 per month, per kilowatt (kW) of monthly standby contract demand[1].

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

DETERMINATION OF MONTHLY STANDBY CONTRACT DEMAND

Monthly Standby Contract Demand (MSCD) in kW is determined using the following formula:

$$MSCD = LWPFD - \mathit{min}\left(LWPFD, \left(\sum_{i=1}^{n} CCi * GCi\right)/(1+PR)\right)$$

Where :

LWPFD is LRS Winter Peak Firm Demand in respect of each billing month calculated as follows:

$$LWPFD = \sum_{i=1}^{k} (CMPFDi * CMDAFi)$$

"k" is the number of otherwise applicable bundled service rate classes to RtR customers of LRS.

"CMPFDi" is hourly kW Class Monthly Peak Firm Demand of the LRS firm load in each tariff class at the time of system coincident firm load peak in each month at transmission delivery points (i.e. inclusive of distribution system losses). The CMPFD for the unmetered customer class shall be determined by use of research based class load profile

1 The exclusion of interruptible load customers from this aggregate is in lieu of any credit that would otherwise be applicable to interruptible bundled service load.

Note: Rates shown are indicative and conditional on the Board's approval.

data.

"CMDAFi" is the Class Monthly Demand Adjustment Factor applicable to each class as set out below:

Classes	Jan, Feb, Dec	Mar, Apr	May, June	Jul, Aug, Sep	Oct, Nov
Domestic	1.00	1.27	1.67	2.17	1.47
Small General	1.00	1.21	1.32	1.09	1.28
General	1.00	1.12	1.32	1.05	1.19
Large General	1.00	1.05	1.04	0.78	0.99
Small Industrial	1.00	1.06	1.01	0.94	1.00
Medium Industrial	1.00	1.14	1.08	1.01	1.02
Large Industrial Firm	1.00	1.10	1.03	0.89	1.09
Unmetered	1.00	8.24	7.90	7.68	2.28

"PR" is Planning Reserve (%) (based on Northeast Power Coordinating Council planning criteria, i.e., 20% or as updated)

"CCi" is a capacity contribution factor of LRS' generator to Nova Scotia Power Inc.'s (NS Power or Company) system peak as determined by the Company. The capacity contribution factor may be the subject of periodic adjustment if operating conditions of the generator, such as a prolonged deration, depart from those assumed by the Company.

"GCi" is the generator capacity dedicated to serving LRS load.

"n" is the total number of LRS' generators including those under contract.

SPECIAL CONDITIONS

(1) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(2) The LRS's retail customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design or operation. These specific requirements shall be stipulated by way of a written operating agreement.

Note: Rates shown are indicative and conditional on the Board's approval.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Standby Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to unilaterally make application to the Nova Scotia Utility and Review Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Standby Service Tariff.

NOTE:
Schedule 4A for Renewable to Retail is on pages 7-8

Schedule 4 on pages 2-6 is the existing OATT Schedule which has only minor changes to refer to the proposed Schedule 4A.

Open Access Transmission Tariff

2014 Schedules

SCHEDULE 4: ENERGY IMBALANCE SERVICE

This schedule is applicable to all OATT customers other than Licensed Retail Suppliers (LRS) in the Renewable to Retail market. Energy Balancing Service (EBS) provided under the Energy Balancing Service Tariff and the Generation Forecasting Service set out in Schedule 4A of the OATT will apply to the LRS.

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within an Operating Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

For a bilateral schedule of a single load and its single generator, this ancillary service will be applied to the net of the generation and load imbalance. Otherwise, this Ancillary Service will be applied separately to deviations from load schedules and deviations from generation schedules. This ancillary service does not apply to power exported from the Operating Area, which is covered by the Generation Balancing Service of the Standard Generator Interconnection and Operation Agreement.

Energy Imbalance Service does not apply to inadvertent energy imbalances that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;

- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Energy Imbalance Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Load Energy Imbalance Associated with Point-to-Point or Network Integration Transmission Service:

For each Transmission Customer taking service under Part II or Part III of this Tariff, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

A deviation band of +/- 1.5 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be applied hourly to any net load energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

Parties should attempt to eliminate energy imbalances within the limits of the deviation band within the billing month in accordance to the following:

- For hourly imbalances that arise during peak hours, such imbalances should be eliminated via deliveries or withdrawals during peak hours; and

- For hourly imbalances that arise during non-peak hours, such imbalances should be eliminated via deliveries or withdrawals during non-peak hours.

Net load energy imbalances within the deviation band that have not been eliminated at the end of the billing month will be subject to the charges set below:

- Energy supplied by the Transmission Provider during peak hours to compensate for a net shortfall in peak hours delivery over the billing month will be charged at the average on-peak system marginal cost for the billing month. Energy supplied by the Transmission Provider during non-peak hours to compensate for a net shortfall in non-peak hours delivery over the billing month will be charged at the average non-peak system marginal cost for the billing month.

- Energy supplied to the Transmission Provider during peak hours as a net excess of the peak hours delivery over the billing month will be purchased by the Transmission Provider at the average on-peak system marginal cost for the billing month. Energy supplied to the Transmission Provider during non-peak hours as a net excess of the non-peak hours delivery over the billing month will be purchased by the Transmission Provider at the average non-peak system marginal cost for the billing month.

Energy imbalances outside of the deviation band are not eligible for elimination and are subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net hourly shortfall in delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

<u>Generation Energy Imbalance - Dispatchable Generators:</u>

For Dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Non-Dispatchable Generators

For Non-dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

Energy Imbalances inside a deviation band of +/- 10 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at the hourly system marginal cost in the hour of the deviation.

All deviations from schedule outside of the +/- 10 percent deviation band will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

SCHEDULE 4A: GENERATION FORECASTING SERVICE

For Licensed Retail Suppliers (LRS) in the Renewable to Retail (RtR) market, the energy imbalance service under the OATT is replaced by the energy balancing service (EBS), which is provided under the Energy Balancing Service Tariff in conjunction with this Generation Forecasting Service. This Schedule concerns the accuracy of generation scheduling in the RtR market.

This Schedule does not apply to forecasting discrepancies that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Forecast Deviation Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Each LRS shall use commercially reasonable efforts to provide accurate schedules and forecasts of production from Renewable Low-Impact Generators that are not dispatchable.

To the extent that such schedules or forecasts of hourly production of the aggregate of an LRS's generation resources deviate from the actual production for reasons other than those that occur as a result of actions directed by the Operating Area operator the following charges shall apply:

An hourly deviation band of +/- 10 percent of the aggregate hourly scheduled or forecast quantity (with a minimum deviation band of +/- 2 MW) will be applied hourly to any forecast discrepancy that occurs as a result of the Transmission Customer's scheduled transaction(s).

- Hourly forecast discrepancies falling outside the hourly deviation band during peak hours will be charged at 10% of the average on-peak system marginal cost for the billing month.
- Hourly forecast discrepancies falling outside the hourly deviation band during non-peak hours will be charged at 10% of the average non-peak system marginal cost for the billing month.

Nova Scotia POWER
An Emera Company

JUNE 8, 2015

Proposed
Energy Balancing Service and Standby Service Tariffs for the Renewable to Retail Market

energy everywhere.™

Legislative Directive – Electricity Reform Act

“NS Power shall develop in consultation with stakeholders, and file with the Board for approval, any tariffs, … and any amendments to existing tariffs …, that are necessary to facilitate the purchase of renewable low-impact electricity … including

- a new or amended backup/top-up service tariff
- a new or amended non-dispatchable supplier spill tariff

Rationale

- The output of non-dispatchable low impact renewable generation cannot be controlled on-demand by the operator and matched with RtR customer load on an hourly basis.
- In hours when generation falls below customer load, the utility must provide top-up energy.
- In hours of surplus generation (spill), the utility must absorb it into its system.
- To ensure that service to RtR customers is reliable, the utility must also provide backup/standby service.

BUTUS redesign for RtR

- Energy Balancing Service (EBS) and Standby Service (SS) will be mandatory services provided by NS Power to Licensed Retail Suppliers
- Cost-based: no cost transfer to bundled service customers
- Top-up and Spill services - combined into Energy Balancing Service
- Backup service - replaced by Standby Service

Proposed design of EBS

For the RtR Market, NS Power proposes a new Energy Balancing Service

- Customer charge based on incremental admin costs
- Energy charge for top-up (10.101 ¢/kWh) to include:
  - Annually adjusted fuel cost (6.650 ¢/kWh)
  - Fixed cost for fixed energy-related gen costs (3.451 ¢/kWh)
    - Same philosophy as used in Shore Power rate
- Energy credit (5.27 ¢/kWh) for spill to include
  - Monthly credit reflective of value of incremental energy
  - Year-end compensation adjustment for surplus Spill energy
  - Max. Spill Capacity subject to NS Power approval
- Generation scheduling similar to Market Rules and OATT with addition of a charge for forecasting discrepancies – OATT Schedule 4A: Generation Forecasting Service.
- RtR Load included in NSP system load schedule

Note: Rates shown are indicative and conditional on the Board's approval.

Proposed design of Standby Service

- Instead of amending existing Backup rate, NS Power proposes new SS service for RtR market.
  - Customer charge based on incremental admin costs.
  - Non-coincident Billing demand replaced with ratcheted Monthly Coincident Demand (MCD).
    - MCD is maximum firm demand coincident with system peaks - Dec, Jan, Feb.
    - Separate coincidence values for each (firm) rate class of the LRS' RtR customers, interruptible customers excluded.
    - Recognizes contributions to capacity from 3rd party generators.
  - MCD charge is $5.370/month/kW of maximum firm coincident demand

Note: Rates shown are indicative and conditional on the Board's approval.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Consumer Advocate Data Requests

NON-CONFIDENTIAL

Request DR-1:

Please provide an update on the status of outstanding items in the COSS process.

(a) Please identify the outstanding COSS items that would potentially affect DT rates.

(b) For each of the following COSS items, if NS Power does not believe that the outcome of pending analyses and discussions might affect the DT rates, please explain why:

(i) subfunctionalization of poles, conductors and underground systems between primary and secondary,

(ii) classification of primary and secondary plant between demand and area-spanning (on customer number or some other measure)

(iii) allocation of service drops

(iv) allocation of miscellaneous revenues

(v) allocation of overhead costs

(vi) re-functionalization of a portion of transmission substation costs to distribution substations

(vii) updating of meter costs

(viii) class load data collection and analysis

(ix) development of a line-loss determination model, including transformer loss adjustment.

Response DR-1:

The table below describes the status of the deferred Cost of Service projects.

DR part	U-6 No.	Item	Status
(i) (ii) (iii)	4	Survey of Distribution System inclusive of service drops.	The Company is in the process of analyzing a preliminary study of the Distribution system, and will bring a proposal to stakeholders in the third quarter of 2015.
(viii)	5	Class Load Data Collection and analysis	The Company is in the process of redesign of the load research sample working with a consultant and will provide an update on the status of this project in the third quarter of 2015.
(ix)	6	Line Loss Determination model	Commencement pending completion of the Load Research Sample overhaul per COS Undertaking U-6 stipulation.
(iv)	7	Miscellaneous revenues	Following consultations with stakeholders, which included two Strawman Reports, the Company filed a final report with the UARB on February 9, 2015.
(v)	8	Overhead costs, including technical and construction costs	Following consultations with stakeholders, which included two Strawman Reports, the Company filed a final report with the UARB on February 9, 2015.
(vi)	9	Manual Adjustment for Transmission rate base from Distribution	Following consultations with stakeholders, which included two Strawman Reports, the Company filed a final report with the UARB on February 9, 2015.
(vii)		Update metering costs	This item was agreed to in the Cost of Service hearing as listed in paragraph 168, item 1(e) of Decision 2014 NSUARB 63, M05473, March 11, 2014.
(ix)	10	Review Transformer Loss Adjustment	Following consultations with stakeholders, which included one Strawman Report, the Company is in the process of working on the follow-up report and expects to file with the UARB in the third quarter of 2015.

(a-b) The outstanding COS items that could potentially affect the Distribution Tariff rates include items 4-10. As these items are finalized and incorporated within the Company's

Cost of Service process, the Distribution Tariff rates would be adjusted accordingly and submitted for Board approval.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Consumer Advocate Data Requests

NON-CONFIDENTIAL

Request DR-2:

Regarding the "protective devices which operate in the same manner with or without load on the system" (Strawman at 16):

(a) Please provide the gross and net plant cost in service for protective devices.

(b) Please explain whether NS Power believes that the number, capacity and cost of protective devices that it installs on its system are independent of load, and if so, explain why this is so.

Response DR-2:

(a-b) The referenced statement refers to protective devices, representing a portion of investments in transformers and services, as tracked under FERC accounts but not deemed demand-related category.

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No	Description	Demand Related	Customer Related
365	Overhead Conductors and Devices	Yes	Yes
368	Line Transformers	Yes	Yes
369	Services	No	Yes

Protective devices may include surge arrestors, lighting arrestors, circuit protective devices, etc. The referenced statement was made to illustrate the depth of costing issues in classification of distribution and reflects comments provided in the "Review of Cost-of-Service Methods of Nova Scotia Power, Inc." report, on page 26, prepared by

[1]Electric Utility Cost Allocation Manual by NARUC, January 1992, page 87.

Christensen Association Energy Consulting on April 16, 2013.[2] NS Power does not separately track cost information on protective devices in its system of accounts. For COS purposes, all transformer investments are treated as demand-related and all services as customer-related categories.

[2] M05473, NS Power Cost of Service Study Application, Exhibit N-1, June 28, 2013, Appendix H, Page 76 of 261.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Consumer Advocate Data Requests

NON-CONFIDENTIAL

Request DR-3:

Regarding the assertion that "With generation and transmission rates of open access distribution customers being already exempted from the R/C ratio adjustment there is less compelling reason, from a rate stability perspective, to apply such an adjustment solely to distribution rates which represent about a quarter of the total cost of electricity." (p. 23)

(a) Is NSPI assuming that renewable-to-retail customers in classes with R/C ratios greater than one will receive a discount on their generation charges compared to bundled service, while renewable-to-retail customers in classes with R/C ratios less than one will pay more for generation charges compared to bundled service?

(b) If the transmission charges are reduced for renewable-to-retail customers in classes with R/C ratios greater than one and increased for those in classes with R/C ratios greater than one, and generation charges may be similarly shifted, would that not argue for keeping the R/C ratio for the DT rates at the bundled average, or moving it further from unity, to reduce the artificial incentive or disincentive for taking renewable-to-retail service?

Response DR-3:

(a) As indicated under item #3 of section 9.2 Revenue to Cost Ratios in the Distribution Tariff (DT) Strawman of May 21, 2015, NS Power does not believe that R/C ratios, as applied to bundled service cost, are directly transferable to its individual functional subcomponents such as generation, transmission or distribution. Further, the LRS's charges applicable to its RtR customers with regard to recovery of its generation and transmission costs will not be subject to review or approval by the UARB and may depart from a strictly cost-based approach to accommodate the LRS's business and marketing strategy.

NON-CONFIDENTIAL

(b) In view of the pricing flexibility available to the LRS, NS Power does not believe that using DT pricing level to compensate for perceived R/C ratio effects on unbundled generation and the OATT would be productive. A strictly COS-based DT provides a simple and transparent approach. There is potential that existing bundled R/C class imbalances could cause some incentive or disincentive but it appears these variances would be relatively small and not warrant attempting to maintain alignment with bundled R/C ratios.

NON-CONFIDENTIAL

Request DR-4:

Please explain why NSPI believes that recovering all DT revenue for classes with demand charges from demand charges on the customer's single maximum monthly or annual load, rather than a broader measure of the customer's contribution to maximum loads on distribution equipment.

(a) Does NSPI agree that a customer with many high-load hours would likely contribute more to the capacity requirements and costs of the distribution system than a customer with just one hour at the same maximum load?

(b) Please identify the seasonal and daily time periods in which feeders and substations are most likely to experience peak or near-peak load.

(c) Please provide any data on the timing and magnitude of load on each distribution substation and each feeder for which NS Power has such data.

Response DR-4:

Please refer section 9.3.2 Customers on Demand Charges of the Distribution Tariff Strawman Report of May 21, 2105.

(a) The cost of the distribution system, as driven by the amount of investment in distribution infrastructure, is primarily determined by a customer's instantaneous demand on the system, as opposed to duration of its usage or energy, and also the number of customers attached to the system. Please refer to the example distribution planning study provided in **Attachment 1** (originally provided in Matter M06514, the NS Power 2015 Annual Capital Expenditure Plan), for the usage considerations in investment decisions. Consistent with this, investment and costs of the system are classified between demand-

Renewable to Retail (NSUARB M06214)
NSPI Responses to Consumer Advocate Data Requests

NON-CONFIDENTIAL

and customer-related categories.[1] Accordingly, it is appropriate to recover these costs through demand charges as applicable to monthly metered customer demands.

(b-c) Please refer to **Attachment 2**, which shows an illustration of the times of annual peaks on bulk power substations, using data from September, 2013. As demonstrated under column F, Peak Occurrence, substation load tends to peak during mornings and evenings during the winter. However, there are some substations that register their peak load outside of these periods, and there are several substations which peak during non-winter months.

[1] This classification is ascertained by NARUC's manual pages 87 and 88.

Nova Scotia POWER
An Emera Company

New Minas Feeder Reconfiguration
DISTRIBUTION PLANNING STUDY

Report number 315-1115-W69

Revision		Date	Prepared by	Reviewed by	Approved by
0	Issued for Study	15-Nov-2012	JMQ		
1	Issued for Release	21-Oct-2013	JMQ	JC	

EXECUTIVE SUMMARY

This study was initiated by the construction of the new 99V-Highbury substation, constructed on Highbury School Road, outside of New Minas. This study is an update of the New Minas Planning Study, report 261-0608-W66.5. This study will outline the feeder extents for the new 99V-Highbury substation, created by transferring load from 22V-New Minas to 99V-Highbury.

The study will revise the feeder configurations of 99V-Highbury, 22V-New Minas, as well as 36V-Hillaton to reduce transformer loading.

A future study will be required to investigate the feasibility of introducing automatic transfer schemes. These schemes are recommended to be introduced in the 2015 capital year.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1.0 SCOPE

This study was initiated as a result of the construction of the new 99V-Highbury substation, outside of New Minas. The construction of this substation had been recommended by a previous study, 261-0608-W66.5. Given the time between completion of the initial study and the construction of the substation, a review of the new and existing distribution feeders was required.

This study will define the feeder extents for the new feeders, supplied by 99V-Highbury as well as the reallocation of the existing feeders to more evenly distribute load in the area. The reduction in load will be realized at the transformers located at the 22V-New Minas and 36V-Hillaton substations.

A future protection study will be required, to determine the location and application of down-line reclosers and to investigate the application of automatic transfer schemes that could be created between the 22V-New Minas, 36V-Hilaton and 99V-Highbury feeders.

2.0 EXISTING SYSTEMS

The existing system has been fully described in the previous study. A brief summary has been included, in the following sections of the report.

2.1 Transmission

The existing 138kV, at 43V-Canaan Road, is supplied via L-6012 from 17V-St.Croix and L-6004 from 90H-Sackville. The 138kV at 43V-Canaan Road is stepped down to 69kV, via the two autotransformers, 43V-T61 and 43V-T62.

Both 22V-New Minas and 36V-Hillaton are supplied via L-5033 from 43V-Canaan Road. The 50V-Klondike substation is supplied via L-5021, from 43V-Canaan Road. The 55V-Waterville substation is supplied via the 56V-Waterville Tap, off of L-5053.

A new 138kV transmission line, L-6052, has been constructed from 43V-Canaan Road, to the new substation, 99V-Highbury.

2.2 Sub-Transmission

The eastern Annapolis Valley is supplied at 69kV via the two autotransformers at 43V-Canaan Road. The new 99V-Highbury substation will be supplied via 138kV. The System Operating Diagrams are attached in Appendix A.

Table 1 Valley Area Sub-Transmission

Substation	Auto-Transformer Data				
	ID	MAN	kV	Rating	Age
43V-Canaan Road	T61	Westinghouse	138-72	30/40/50//56	1969
43V-Canaan Road	T62	Maloney Electric	138-72	33.6/44.8//56	1990

2.3 Distribution

The distribution system being studied, in this report is the area supplied by 22V-New Minas and 36V-Hillaton. Load data from 50V-Klondike and 55V-Waterville has been included in this study as these substations were considered as potential areas where load could be transferred, for contingency purposes.

These substations have also been included because of their close proximity to the 99V-Highbury substation.

Table 2 New Minas Area Distribution Transformers

Substation	Transformer Data				
	ID	MAN	kV	Rating	Age
22V-New Minas	T51	Federal Pioneer	69-13.2	7.5/10/12.5	1987 R
22V-New Minas	T52	Westinghouse	69-13.2	7.5/10/12.5//14	1987
36V-Hillaton	T1	Federal Pioneer	69-12.47	7.5/10//11.2	1974
50V-Klondike	T51	ABB	69-26.4	15/20//25	1993
55V-Waterville	T51	Federal Pioneer	69-13.2	7.5/10/12.5//14	1976
55V-Waterville	T52	Westinghouse	69-12.47	7.5/10//11.2	1972

2.3.1 22V-New Minas

The 22V-New Minas substation is supplied via L-5033, from 43V-Canaan Road. The two transformers, 22V-T51 and 22V-T52, have both been trending at or above their nameplate ratings for the past several years winter peak (refer to Appendix B). In addition to the transformers trending above nameplate, three of the feeders from this substation have been trending above 300A during winter peak. With the construction of the new substation, 99V-Highbury, the reallocation of the 22V-New Minas load will alleviate the heavily loaded transformers and feeders.

2.3.2 36V-Hillaton

Currently, 36V-Hillaton is radially fed via an extension of L-5033 from 22V-New Minas. The load supplied via this substation mostly radiates outward from the substation with few opportunities to transfer load between feeders. The substation transformer, 36V-T1 has been trending above its nameplate rating, in each of the last 10 winters (where load check data has been available).

2.3.3 99V-Highbury

The new 99V-Highbury Road substation is located adjacent to Highway 101 near Highbury School Road. This location places this new source in a central location to a large portion of the load currently supplied via 22V-New Minas allowing for the transfer of load to the new substation.

3.0 LOAD HISTORY AND FORECAST

The loading for those feeders being studied is largely residential, with a small number of commercial customers. As illustrated in the load history for these feeders (Appendix B), the feeders being studied have had a larger winter peak than summer peak. Historical load data for the feeders and transformers being studied was collected from the Distribution Load Check Database and presented in Table 3 below. SCADA data is available for the 69kV line (L-5033) supplying both 22V-New Minas and 36V-Hilaton substations. The combined load and associated load growth rate from this data is also included below for comparison purposes.

3.1 Load History

Customer load has been generally consistent in this portion of the Annapolis Valley, with a slight increase due to increased residential developments. Load growth projections for the area have been outlined below in Table 3. Overall growth rates have been determined based on 15 years of load data, as presented in the table below:

Table 3 Growth Rates; 1998 - 2013

Transformer	2013 Load in MVA	Load Growth	Notes
22V-T51	13.0	1.75%	
22V-T52	18.4	1.28%	
22V Total	30.4	1.62%	Total Substation Load
36V-T1	13.5	0.83%	
L-5033	45.6	0.72%	Radial supply to 22V and 36V
55V-T51	8.6	-4.28%	2nd Transformer added in 2009
55V-T52	10.4		Not enough data to forecast
55V Total	18.7	2.09%	Total Substation Load
50V-T51	21.4	0.44%	New 25kV Transformer installed 2008
43V-505	21.0	0.32%	Breaker supplying L-5021 to 50V-Klondike
Feeder	**2013 Load in AMPS**	**Load Growth**	**Notes**
22V-312	303	0.83%	
22V-313	183	0.75%	
22V-314	128	-0.27%	
22V-321	276	1.39%	
22V-322	325	-0.54%	
22V-323	317	1.51%	
36V-301	191	-1.50%	
36V-302	191	0.39%	
36V-303	177	-1.21%	
55V-313	224	3.03%	
55V-314	189	-4.07%	
55V-322	235		New feeder added in 2009
55V-323	223		New feeder added in 2009
50V-401	184	-2.44%	25kV Feeder
50V-402	254	0.49%	25kV Feeder

3.2 Load Forecast

The 90th percentile load forecasts for the 12kV feeders at 22V-New Minas and 36V-Hillaton are presented in the following tables. The overall growth, in the area, is forecasted to be approximately 0.72%, as determined by the radial 69kV line (L-5033) supplying both the 22V-New Minas and 36V-Hilaton substations. The tables below illustrate the overall projected load growth, by feeders and transformers.

Table 4 **90th Percentile Load Forecast for 22V-New Minas feeders**

	22V-312	22V-313	22V-314	22V-321	22V-322	22V-323
2012 / 2013	315	214	148	265	303	348
2013 / 2014	318	216	148	269	302	354
2014 / 2015	321	218	148	274	300	360
2015 / 2016	324	219	147	278	298	366
2016 / 2017	326	221	147	282	297	372
2017 / 2018	329	223	147	286	295	377
2018 / 2019	332	224	146	290	294	383
2019 / 2020	335	226	146	294	292	389
2020 / 2021	337	228	145	298	290	395
2021 / 2022	340	230	145	302	289	401
2022 / 2023	343	231	145	306	287	407
2023 / 2024	347	233	144	310	286	412
2024 / 2025	348	234	144	314	284	418
2025 / 2026	351	236	144	318	283	424
2026 / 2027	354	238	143	322	281	430
2027 / 2028	357	240	143	326	279	436

Table 5 **90th Percentile Load Forecast 36V-Hillaton feeders**

	36V-301	36V-302	36V-303
2012 / 2013	189	236	239
2013 / 2014	187	237	236
2014 / 2015	184	238	234
2015 / 2016	182	239	231
2016 / 2017	179	240	228
2017 / 2018	176	240	226
2018 / 2019	174	242	223
2019 / 2020	171	242	220
2020 / 2021	169	243	218
2021 / 2022	166	244	215
2022 / 2023	164	245	212
2023 / 2024	161	246	210
2024 / 2025	158	247	207
2025 / 2026	156	248	204
2026 / 2027	153	249	202
2027 / 2028	151	250	199

Table 6 90th Percentile Load Forecast for Eastern Valley Transformers

	22V-T51 7.5/10/12.5	22V-T52 7.5/10/12.5//14	22V Total	36V-T1 7.5/10//11.2	L-5033	55V-T51 7.5/10/12.5//14	55V-T52 7.5/10//11.2	55V-Total	50V-T51 15/20//25
2012 / 2013	14.4	19.1	34.7	13.9	46.4	13.2	15.0	22.4	22.3
2013 / 2014	14.7	19.4	35.3	14.0	46.7	12.8	17.0	22.9	22.4
2014 / 2015	15.0	19.7	36.0	14.1	47.1	12.4	19.1	23.5	22.5
2015 / 2016	15.2	19.9	36.6	14.3	47.4	12.0	21.1	24.0	22.6
2016 / 2017	15.5	20.2	37.2	14.4	47.8	11.5	23.2	24.5	22.7
2017 / 2018	15.8	20.5	37.9	14.5	48.1	11.1	25.2	25.1	22.8
2018 / 2019	16.1	20.7	38.5	14.6	48.5	10.7	27.2	25.6	22.9
2019 / 2020	16.4	21.0	39.1	14.8	48.8	10.3	29.3	26.2	23.0
2020 / 2021	16.7	21.3	39.8	14.9	49.2	9.8	31.3	26.7	23.1
2021 / 2022	17.0	21.5	40.4	15.0	49.6	9.4	33.4	27.3	23.2
2022 / 2023	17.2	21.8	41.0	15.1	49.9	9.0	35.4	27.8	23.3
2023 / 2024	17.5	22.1	41.7	15.2	50.3	8.6	37.5	28.3	23.4
2024 / 2025	17.8	22.3	42.3	15.4	50.6	8.1	39.5	28.9	23.5
2025 / 2026	18.1	22.6	42.9	15.5	51.0	7.7	41.5	29.4	23.6
2026 / 2027	18.4	22.9	43.6	15.6	51.3	7.3	43.6	30.0	23.7
2027 / 2028	18.7	23.1	44.2	15.7	51.7	6.9	45.6	30.5	23.8

4.0 OVERLOADS AND OTHER CONSIDERATIONS

The following section identifies issues that warrant correction based on NSPI's *Capital Expenditure Justification Criteria*.

4.1 Substation Transformer Overloads

The following substation transformers have peaked above their nameplate ratings, but below 133% of their top rating, for the following years;

- 22V-T51 2013, 2011. 2010, 2009, 2008
- 22V-T52 2013, 2012, 2011, 2010, 2009, 2008, 2006, 2005, 2002
- 36V-T1 2013, 2012, 2011, 2010, 2009, 2008, 2006, 2005, 2004, 2003, 2002,

4.2 Feeder Overloads

The following list of feeders has peaked above 300A for the following years;

- 22V-312 2013, 2010, 2004
- 22V-322 2013, 2010, 2005, 2004, 2003, 2001
- 22V-323 2013, 2012, 2011, 2003, 2002

5.0 SOLUTIONS AND EVALUATION

This study is examining the eastern Annapolis Valley distribution system, with consideration of the new substation, 99V-Highbury. The alternatives outlined below will discuss various options to offload existing substations via the new source.

These alternatives focus on the transfer of existing load from 36V-Hillaton and 22V-New Minas onto the new 99V-Highbury substation. Feeders from these two 12kV substations are in close proximity to the new substation and the transformers at these substations have seen peak loading above nameplate rating in recent years.

The recommendations for the report will be compiled from the alternatives outlined below.

5.1 99V-Highbury Feeder Extents

There are a variety of feeder configurations possible with respect to the addition of the new source, 99V-T61. Given the location of the substation, and its proximity to a large portion of load currently serviced by 22V-New Minas, a large reduction of 22V-323 and 22V-312 load is possible without much difficulty.

22V-323 is the longest feeder supplied by 22V-New Minas, with a portion containing densely populated suburban residential load, as well as a large portion of rural residential load. This feeder can be divided at the intersection of New Minas Connector Road and Prospect Road. This will enable the separation of the suburban and rural customers on a feeder that is greater than 100kms in length.

Further subdividing the remaining portion of 22V-323 along Highbury Road to Commercial Street in New Minas will further reduce the load on 22V-T52.

The third new feeder to be supplied via 99V-Highbury is a large portion of the existing 22V-312 feeder from the intersection of Highbury Road and Prospect Road to Commercial Street. Reallocating this load to a new feeder will reduce the overall loading on 22V-T51.

The fourth feeder to be supplied via 99V-Highbury will be used to transfer load from 22V-322. Transferring load from 22V-322 by way of a line extension along the New Minas Connector Road via the Cornwallis River Crossing, to Belcher Street will enable the transferring of load from 22V-322 to further enable the offloading of 36V-301. The construction of this new express feeder also enables the creation of an additional feeder tie with 22V-314 at the intersection of Commercial Street and the New Minas Connector Road, at some point in the future.

5.2 36V-Hillaton Load Reduction

Reducing the loading on 36V-Hillaton needs to be addressed in the feeder reconfigurations associated with the new substation, 99V-Highbury. Given the loading on 36V-T1 has exceeded its nameplate rating in the past several winters, the opportunity to address these issues needs to be considered where a new source is being added in the area. The opportunity to transfer load to adjacent substations and the replacement of 36V-T1 is outlined below.

Replacing the existing 36V-T1, a 7.5/10//11.2MVA, with a larger 15/20/25MVA unit will meet the current loading requirements, for the future. The load growth, in the area is roughly 0.83% annually. In replacing the 36V-T1 with a larger unit, there would be a requirement to install a mobile substation for the duration of work required, to replace the substation transformer and base. The installation of a transfer bus and SCADA controls would also be required.

However given the proximity of 36V-Hillaton feeders with the feeders from adjacent substations, there exists the potential to transfer load from 36V-Hillaton, onto the adjacent feeders from 22V-New Minas and 50V-Klondike.

22V-New Minas has only one feeder currently crossing the Cornwallis River, 22V-322. This crossing consists of a double circuit with the 36V-Hillaton 69kV supply, L-5039. Currently, this feeder is approaching its loading limits during winter operations. Construction of another Cornwallis River crossing will require the construction of a new distribution line, as well as securing a new right of way (ROW). The locations for this new crossing are limited to the two existing road crossings at Highway 358 and Cornwallis River Crossing.

Of these two crossing alternatives, the Cornwallis River Crossing is the better choice. In that a new line constructed at this location offers the ability for the crossing to be supplied by a feeder from either 22V-New Minas or 99V-Highbury and the pole line is relatively straight in comparison to Highway 358 which has more curves which would require additional guying and anchoring. In either case, there will be a requirement to obtain environmental permits prior to construction.

An alternative to constructing a new river crossing would be to use the existing infrastructure, via 50V-Klondike by way of placing a stepdown at the end of the 50V-401, on Aldershot Road. In placing the stepdown at this location, the existing 12kV feeder, 36V-303 would need to have either a two phase addition or a partial conversion to the Lakewood Road intersection and place the stepdowns at that location. In adding these stepdowns, the overall load able to be transferred would be less than that available with a new river crossing and lightly loaded feeder.

5.2.1 Alternative A Replace 36V-T1

The existing 36V-Hillaton transformer, 36V-T1 has been exceeding its nameplate rating, 7.5/10//11.2MVA, during the winter peak, for the last several years. The three feeders supplied via 36V-T1 are not presently heavily loaded, with 36V-303 peaking beyond 250A, in the past two winters.

The top rating on the existing transformer, 36V-T1 is 11.2MVA. A larger 15/20/25MVA transformer would meet the current needs, as well as the future load growth, in the area. Additionally, the installation of a larger transformer will increase the contingency opportunities with the adjacent substations, in the area, including 55V-Waterville.

To implement this alternative, a variety of substation upgrades would be required, including the construction of a transfer bus and the installation of an RTU, for SCADA controls.

5.2.2 Alternative B 36V-Hillaton Load Reduction via 22V-New Minas

In conjunction with the construction of the 99V-Highbury substation, the construction of an express feeder from the Prospect Road to Belcher Street, will allow for the offloading of 22V-322. This load reduction would then be able to be cascaded to the 36V-Hillaton feeders, by way of a load transfers.

These load reductions would commence with transferring the load on 22V-322, east of the existing Cornwallis River crossing to the new 99V-Highbury feeder. Upon completion of this load transfer, load from 36V-301 would then be transferred to 22V-322.

The completion of these load transfers would reduce the overall loading on 36V-T1, such that the load peak would not exceed 133% of nameplate rating for the foreseeable future.

5.2.3 Alternative C 36V-Hillaton Load Reduction via 50V-Klondike

An additional alternative, to reduce the load on 36V-303, would be the addition of 3x500kVA stepdowns at the end of 50V-401, on Aldershot Road. These new stepdowns would assume the load from 36V-303, along Aldershot Road, to the intersection at Sherman Belcher Road. D316-110, on Lydiard Road would need to be opened.

To offset the load added to 50V-Klondike a conversion of the existing 4kV stepdowns, 652V and 653V, will be required.

5.2.4 Recommended Alternative

Alternative B has been selected as the recommended alternative because it is the least cost alternative; refer to the Economic Analysis Model in Appendix C. This alternative reduces the load on 36V-T1, while offering the greatest flexibility to supply future load growth in the Williamsport and Canning areas for the foreseeable future.

6.0 RECOMMENDATIONS

This study recommends the offloading of two 22V-New Minas feeders, 22V-323 and 22V-312, to three new feeders supplied from the new substation, 99V-Highbury. The study also recommends the construction of a new feeder from 99V-Highbury to Belcher Street via Cornwallis River Crossing. This new feeder will assume a portion of load from 22V-322. The load reduction will then be cascaded to adjacent 36V-Hilaton feeders, to reduce the overall load on 36V-T1. The details of these recommendations are outline below, by capital year.

Also included in the recommendations of this study are plans for future load transfers within the 36V-Hilaton feeders to further balance the loading across the three feeders.

6.1 2013 Capital Year

For the 2013 capital year, the construction of the 99V-Highbury Road substation will be completed. In conjunction with this, the determination of the feeder extents will be completed.

6.1.1 99V-Highbury Feeder Extents Part-1

This portion of the project will outline the feeder extents for one new feeder, 99V-3X1, to be supplied via the new 99V-Highbury substation. This feeder will assume all of load from the existing 22V-323 beyond the Prospect Road and New Minas Connector Road intersection (approximately 250A, under peak loading). Refer to Figure 1 below. This will be accomplished by:

- Using the existing routing for 22V-323, exit the 99V-Highbury substation and ensure that all existing taps are transferred to 99V-3X1 up to the Prospect Road and New Minas Connector Road intersection.
- Remove recloser R316-014 from its current location on Prospect Road.
- Remove capacitor P316-011.

Figure 1 New 99V-Highbury Feeder, 99V-3X1

6.1.2 99V-Highbury Feeder Extents Part-2

This portion of the project will outline the feeder extents for two feeders, 99V-3X2 and 99V-3X3, to be supplied via the new 99V-Highbury substation. These feeders will assume portions of load from the existing 22V-323 and 22V-312 (approximately 40A and 93A respectively, under peak loading). Refer to Figure 2 below. This will be accomplished by:

- Construct a double circuit on Prospect Road, from New Minas Connector Road to Highbury Road.
- Highbury Road, east of New Minas Connector Road will be supplied via 99V-3X2, on the newly constructed portion of the double circuit. A new open point will be installed at the intersection of Highbury Road and Commercial Street, in New Minas.
- Prospect Road, including the load currently being supplied via 22V-323, will be supplied via 99V-3X3. Open D316-356, on Prospect Road.

Figure 2 **99V-3X2 and 99V-3X3 feeder extents**

6.2 2014 Capital Year

The 2014 capital year will see the construction of a fourth feeder from 99V-Highbury, to Belcher Street, to enable the offloading of 36V-Hillaton resulting in a load reduction on 36V-T1

6.2.1 99V-Highbury New Feeder

This portion of the project will see the construction of a new feeder, 99V-3X4, from the underground to overhead transition on the New Minas Connector Road to Belcher Street. This new feeder will be used to offload 22V-322. Refer to Figure 3 and Figure 4 below. This will be accomplished by:

- Construct new three phase 336AASC and 4/0 neutral on the New Minas Connector Road from Prospect Road to Commercial Street.
- Construct new three phase 336AASC and 4/0 neutral on the Cornwallis River Crossing from Commercial Street to Belcher Street.
- Install a new recloser on Cornwallis River Crossing, at Belcher Street.

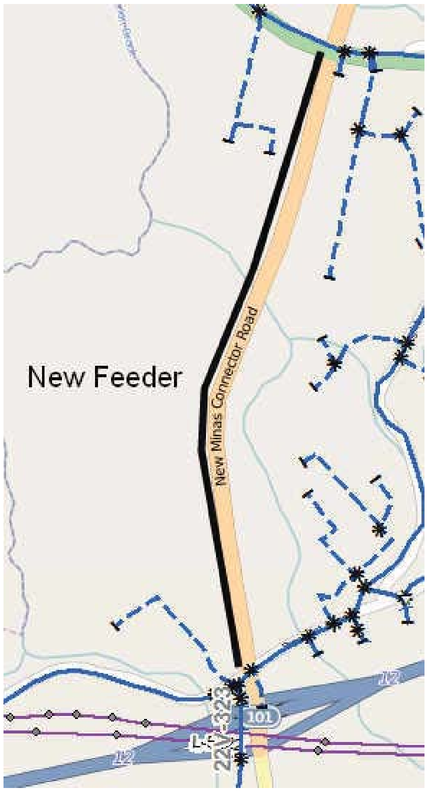


Figure 3 99V-3X4 New Feeder Construction Part-1

Figure 4 99V-3X4 New Feeder Construction Part-2

6.2.2 22V-322 Load Transfer

This portion of the project will outline the load transfer from 22V-322 to 99V-3X4 (approximately 167A, under peak loading). This will transfer the western portion of Belcher Street. Refer to Figure 5 below. This work will be accomplished by:

- Open R3A04201 on Belcher Street.

Figure 5 **22V-322 Load Transfer**

6.2.3 36V-301 Load Transfer

This portion of the project will outline the load transfer from 36V-301 to 22V-322. This will transfer a large portion of 36V-301 load (approximately 112A, under peak loading). Refer to Figure 6 below. This work will be accomplished by:

- Close switches D3A21690 and D316-045, on Highway 358, prior to Church Street.
- Install new open point on Highway 358, north of the intersection with Highway 341.

Figure 6 **36V-301 Load Transfer**

6.3 2015 Capital Year

For the 2015 capital year, the installation of new automatic transfer schemes between 22V-New Minas, 36V-Hilaton and 99V-Highbury feeders will be completed. These transfer schemes will reduce the number of Customer Hours of Interruption (CH) in the area, as well as increasing the contingencies between the three substations.

6.4 2018 Capital Year

The capital items outlined below are to be considered for advancement, in the event that the load increases at 36V-Hilaton in the coming years. A review of the requirement of these items will be required, in 2017.

6.4.1 36V-302 Load Transfer Part-1

This portion of the project will see the transfer of load from 36V-302 to 36V-301. To accomplish this, a double circuit will need to be constructed on Saxon Road (approximately 24A, under peak loading). Refer to Figure 7 below. This work will be accomplished by:

- Construct Double Circuit along Saxon Street, from 36V-Hillaton to Middle Dyke Road.
- Rebuild Highway 221 to three phase 4/0, on Highway 221, from Black Hole Road to Hillaton Road.
- Change Taps on Middle Dyke Road from 36V-303 to 36V-302.

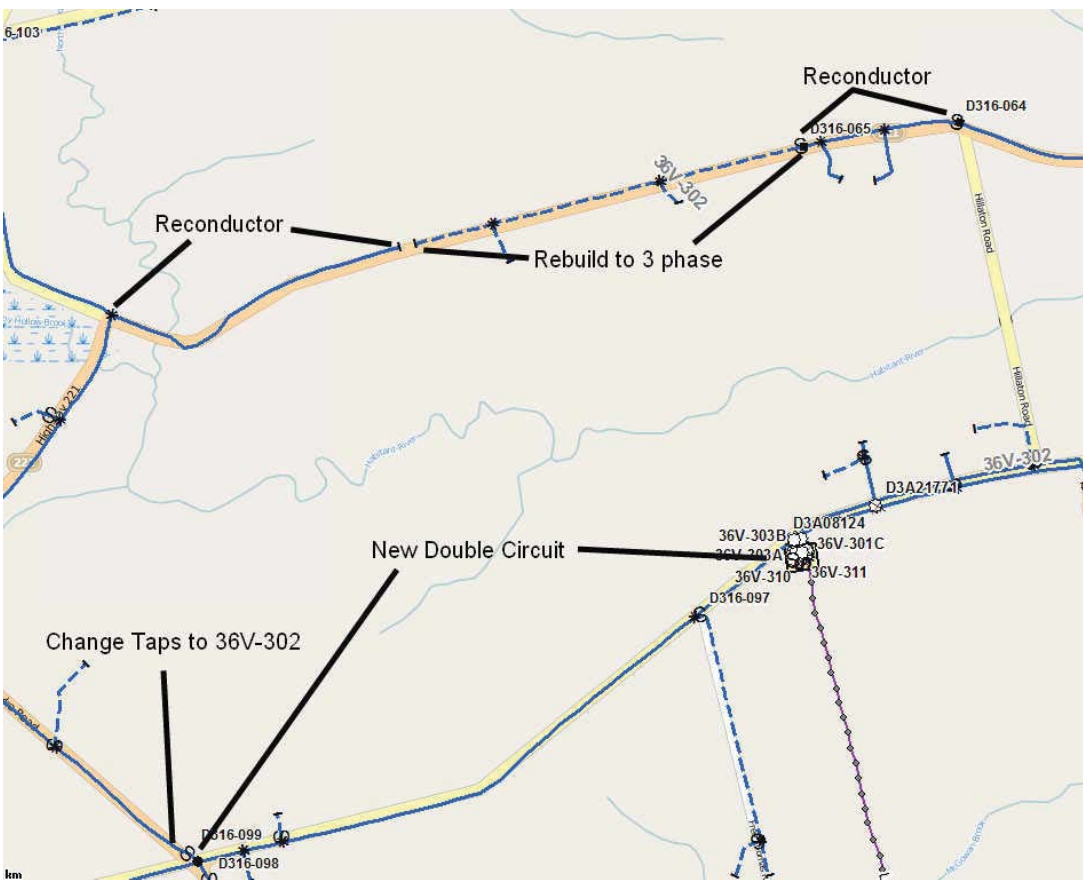


Figure 7 36V-302 Load Transfer Part-1

6.4.2 36V-302 Load Transfer Part-2

This portion of the project will see the completion of the remainder of work required to transfer load from 36V-302 to 36V-301 (approximately 112A, under peak loading). Refer to Figure 8 and Figure 9 below. This work will be accomplished by:

- Rebuild North Avenue from D316-094 to Bessie North Road, to three phase 4/0.
- Install new normally closed switch on Bessie North Avenue and North Avenue.
- Install new normally open switch at Rabbit Square Road and North Avenue.
- Open D316-469 at the intersection of Highway 221, Sheffield Road and Main Street.
- Create a new feeder tie between 36V-301 and 36V-302 on Highway 358, prior to the intersection with Saxon Street.
- Install new normally closed open point on Highway 358, between 36V-301 and 36V-302.
- Install new normally open point on Saxon Road, at the intersection to Highway 358.

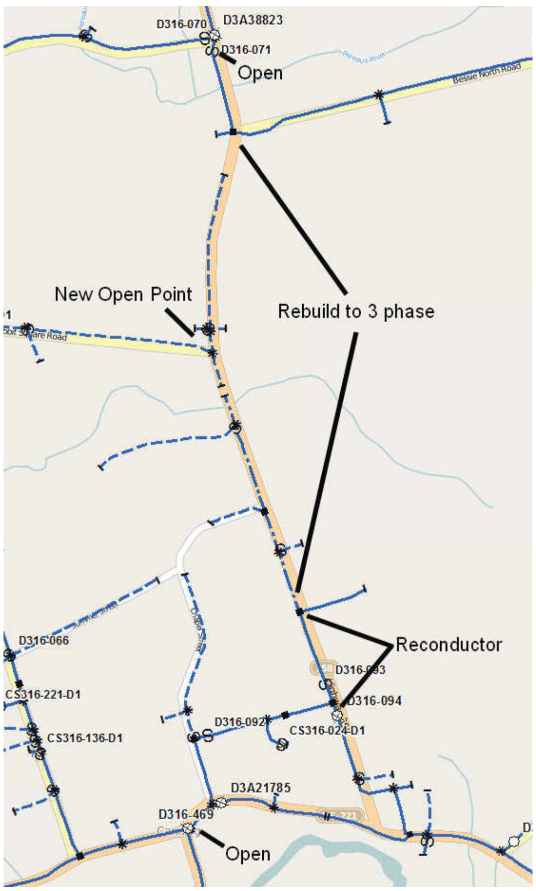


Figure 8 **36V-302 Load Transfer Part-2**

Figure 9 **36V-302 / 36V-301 Tie**

6.4.3 36V-303 Load Transfer Part-1

This portion of the project will transfer load from 36V-303 to 36V-302 (approximately 20A, under peak loading). Refer to Figure 10 below. This work will be accomplished by:

- Install a new open point on Highway 341, east of Middle Dyke Road.
- Rebuild Highway 341, from Middle Dyke Road to D316-108, Gibson Woods Road.
- Reconductor Middle Dyke Road from Saxon Street to Highway 341.
- Close D316-055 and D316-056.
- Install new normally open point at Saxon Street and Sherman Belcher Road.
- Change tap for Middle Dyke Road, at Saxon Street, from 36V-303 to 36V-302.

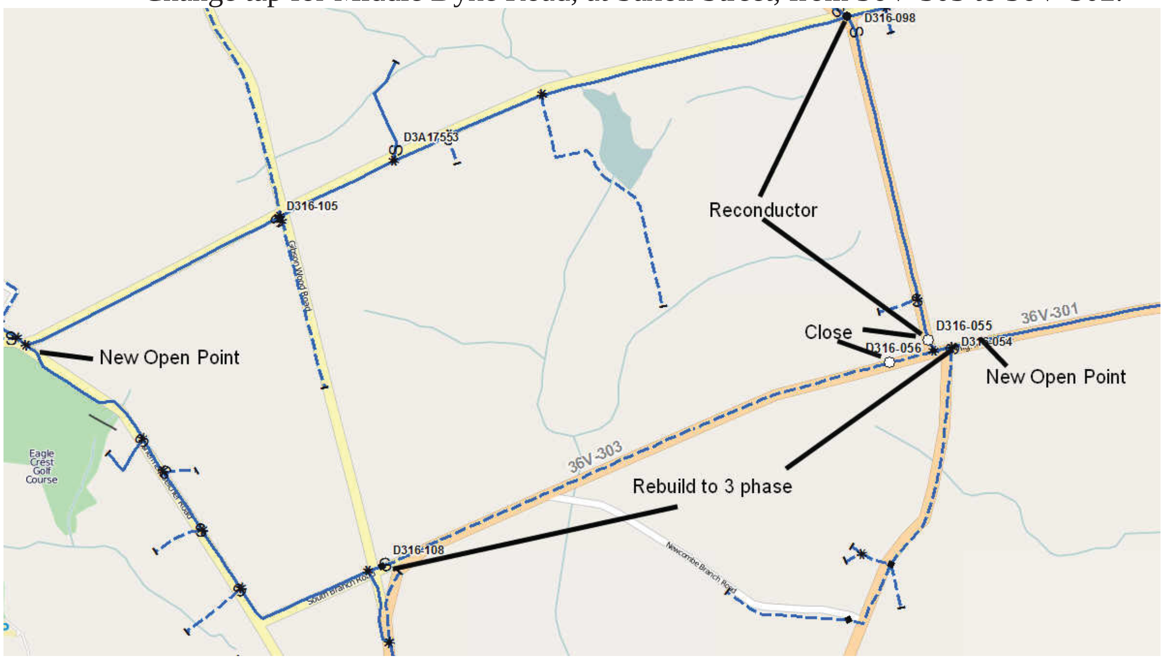


Figure 10 36V-303 Load Transfer Part-1

6.4.4 36V-303 Load Transfer Part-2

This portion of the project will complete the load transfer from 36V-303 to 36V-302 (approximately 32A, under peak loading). Refer to Figure 11 below. This work will be accomplished by:

- Reconductor Lakewood Road and filing in the gap with 2/0 ACSR, primary and neutral.
- Open D316-110 on Lydiard Road.

Figure 11 36V-303 Load Transfer Part2

APPENDIX A

System Operating Diagrams

Appendix A: System Operating Diagrams

[redacted]

Figure 12 System Operating Diagram 43V-Canaan Road

Appendix A: System Operating Diagrams

[redacted]

Figure 13 System Operating Diagram 22V-New Minas

Appendix A: System Operating Diagrams

[redacted]

Figure 14 **System Operating Diagram 36V-Hillaton**

Appendix A: System Operating Diagrams

[redacted]

Figure 15 System Operating Diagram 50V-Klondike

Appendix A: System Operating Diagrams

[redacted]

Figure 16 System Operating Diagram 55V-Waterville

Appendix A: System Operating Diagrams

[redacted]

Figure 17 System Operating Diagram 99V-Highbury

APPENDIX B

Load History and Forecast

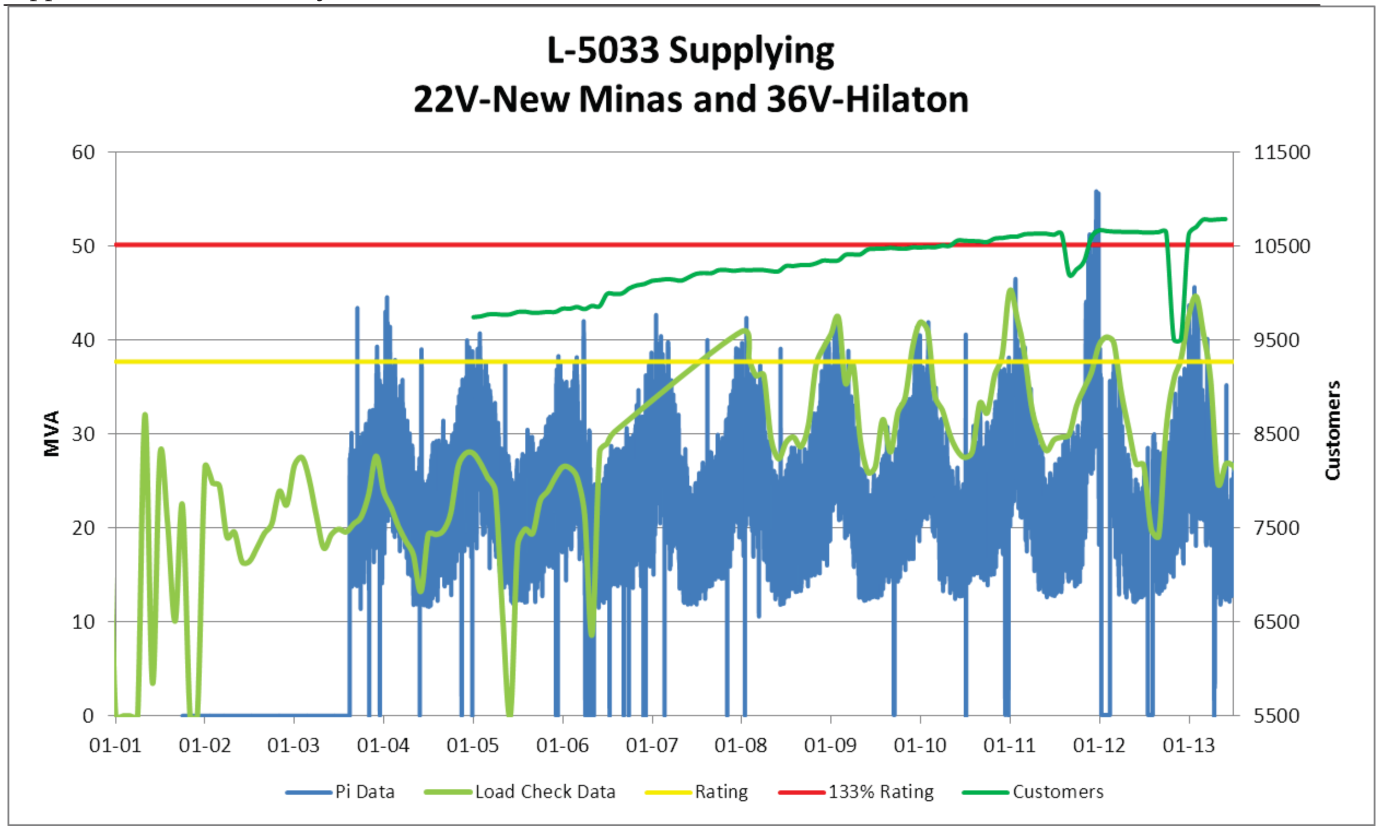


Figure 18 L-5033 Load History

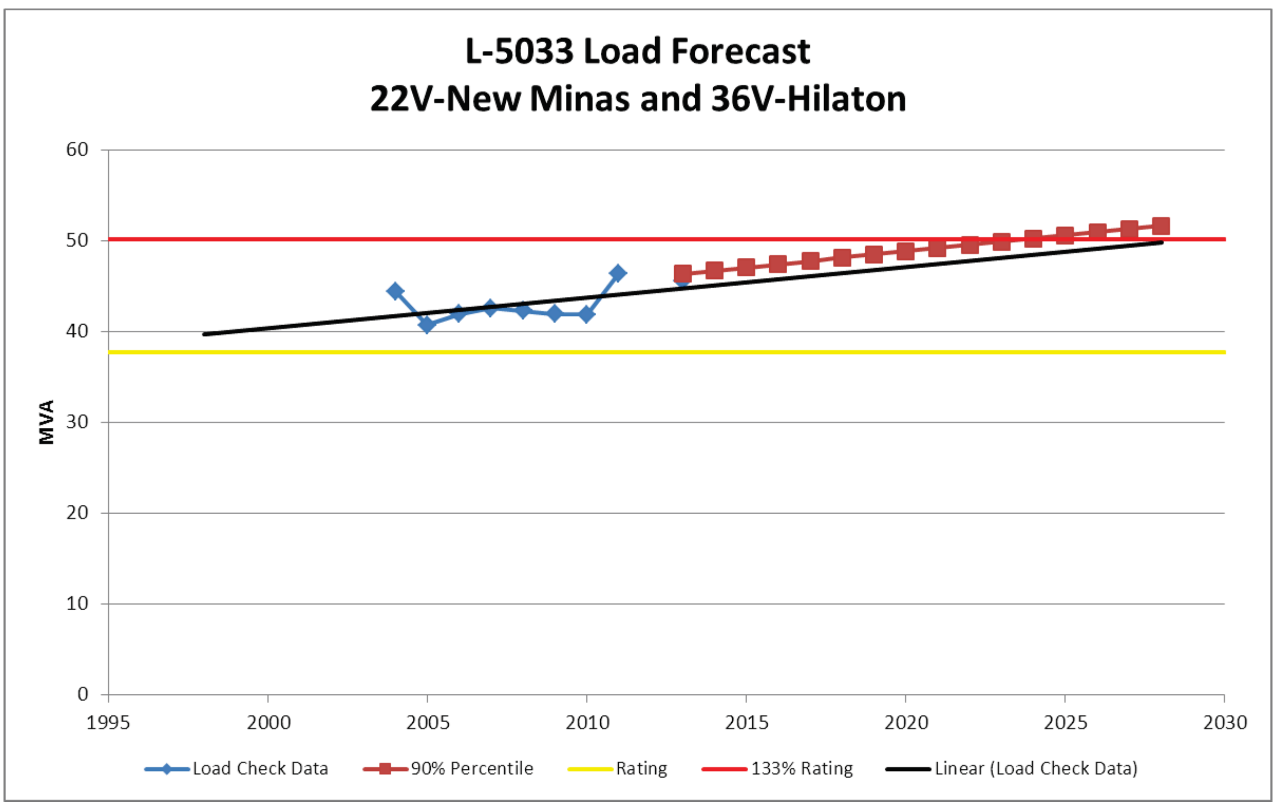


Figure 19 L-5033 Load Forecast

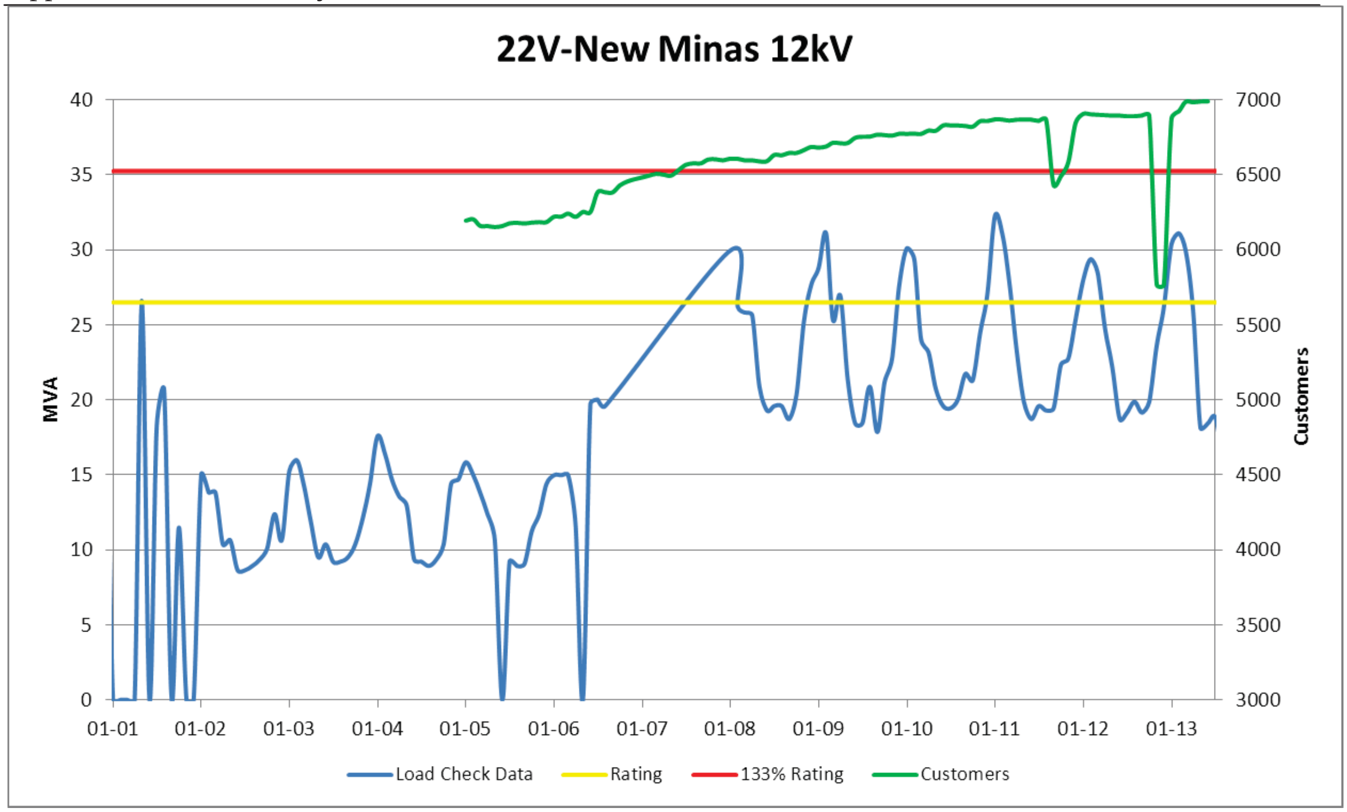


Figure 20 22V-New Minas Load History

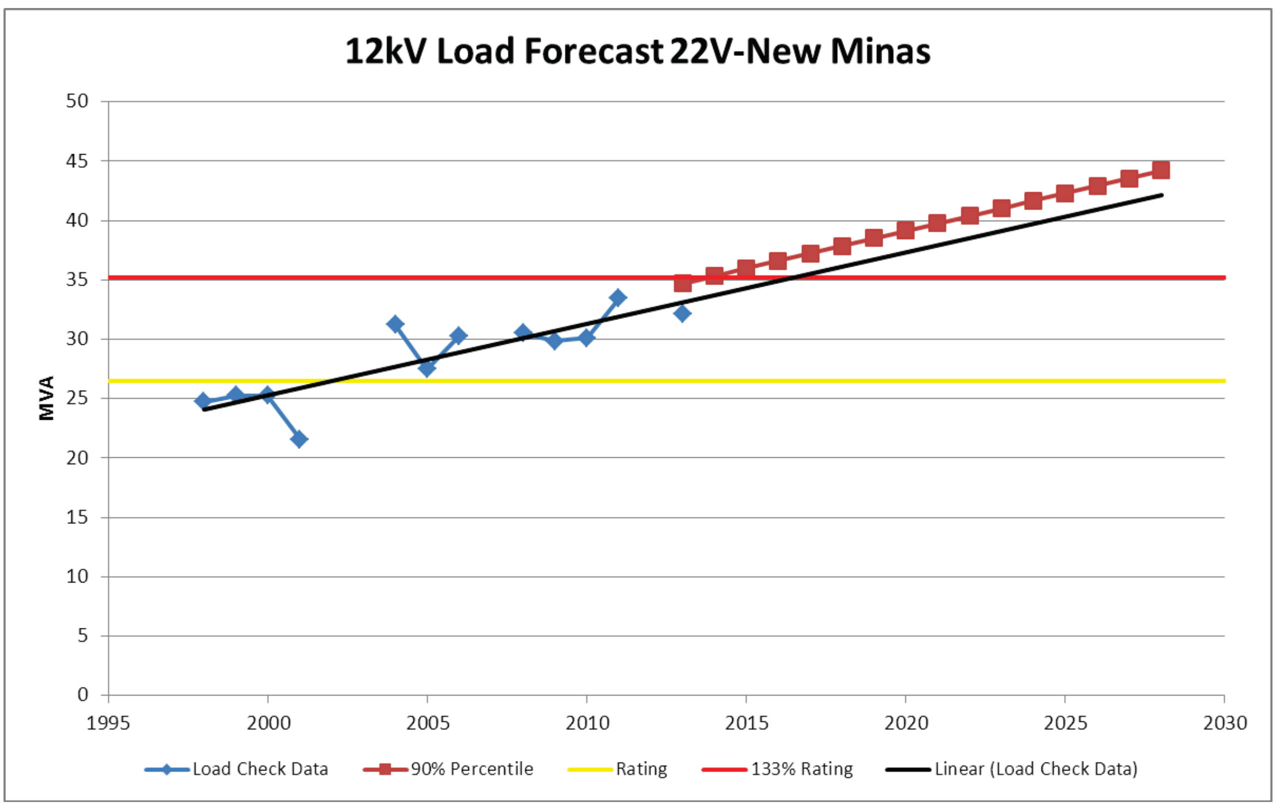


Figure 21 22V-New Minas 12kV Load History

Note: This load forecast is prior to the 99V-Highbury substation being in-service.

Appendix B: Load History and Forecast

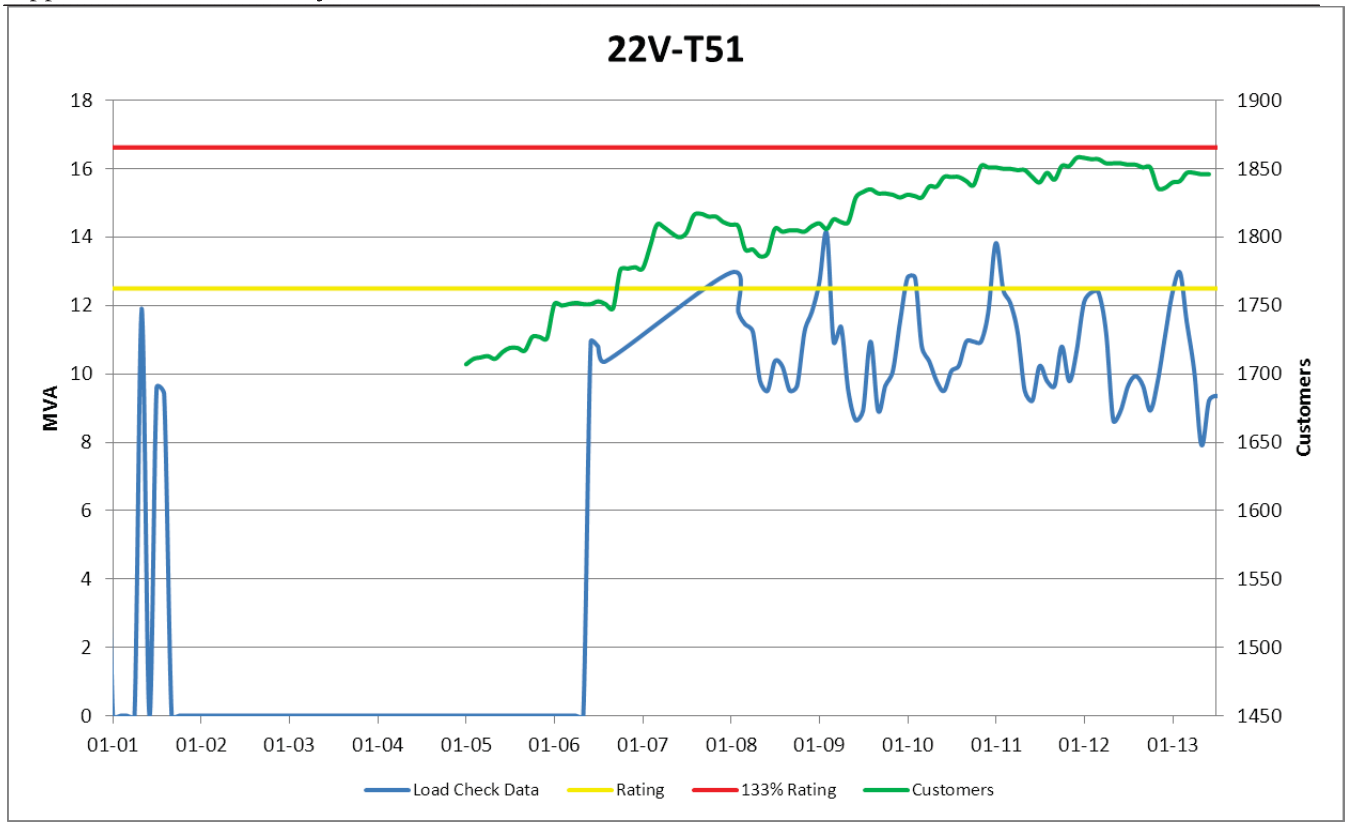


Figure 22 **22V-T51 Load History**

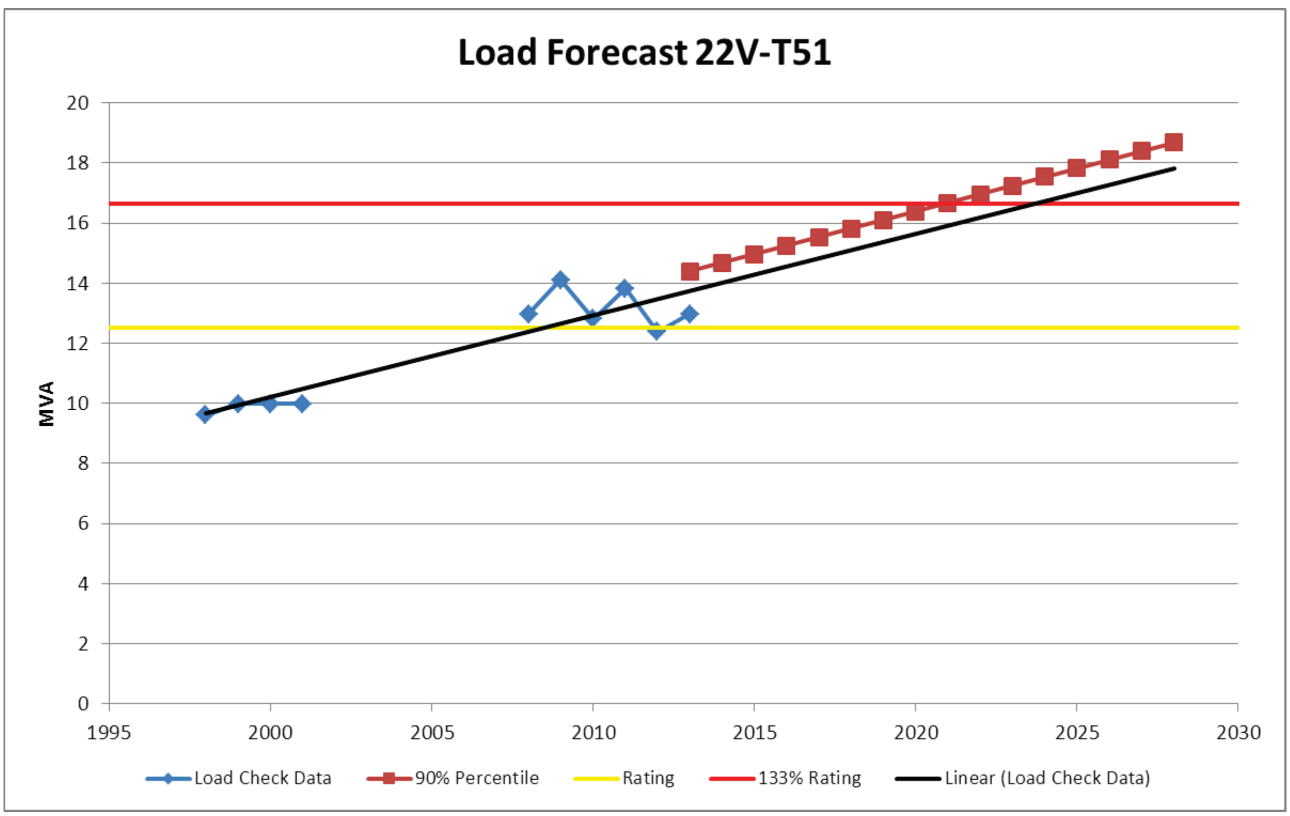


Figure 23 **22V-T51 Load Forecast**

Appendix B: Load History and Forecast

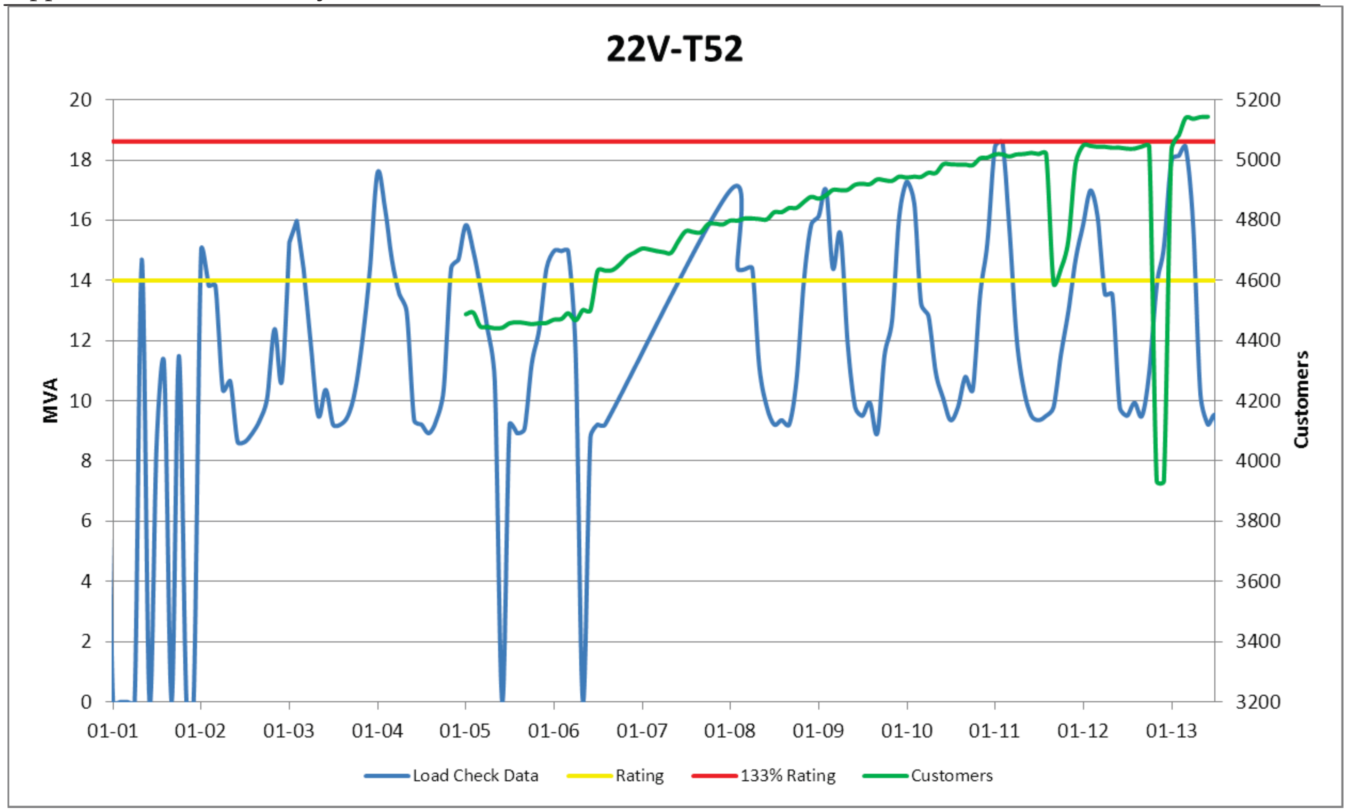


Figure 24 **22V-T52 Load History**

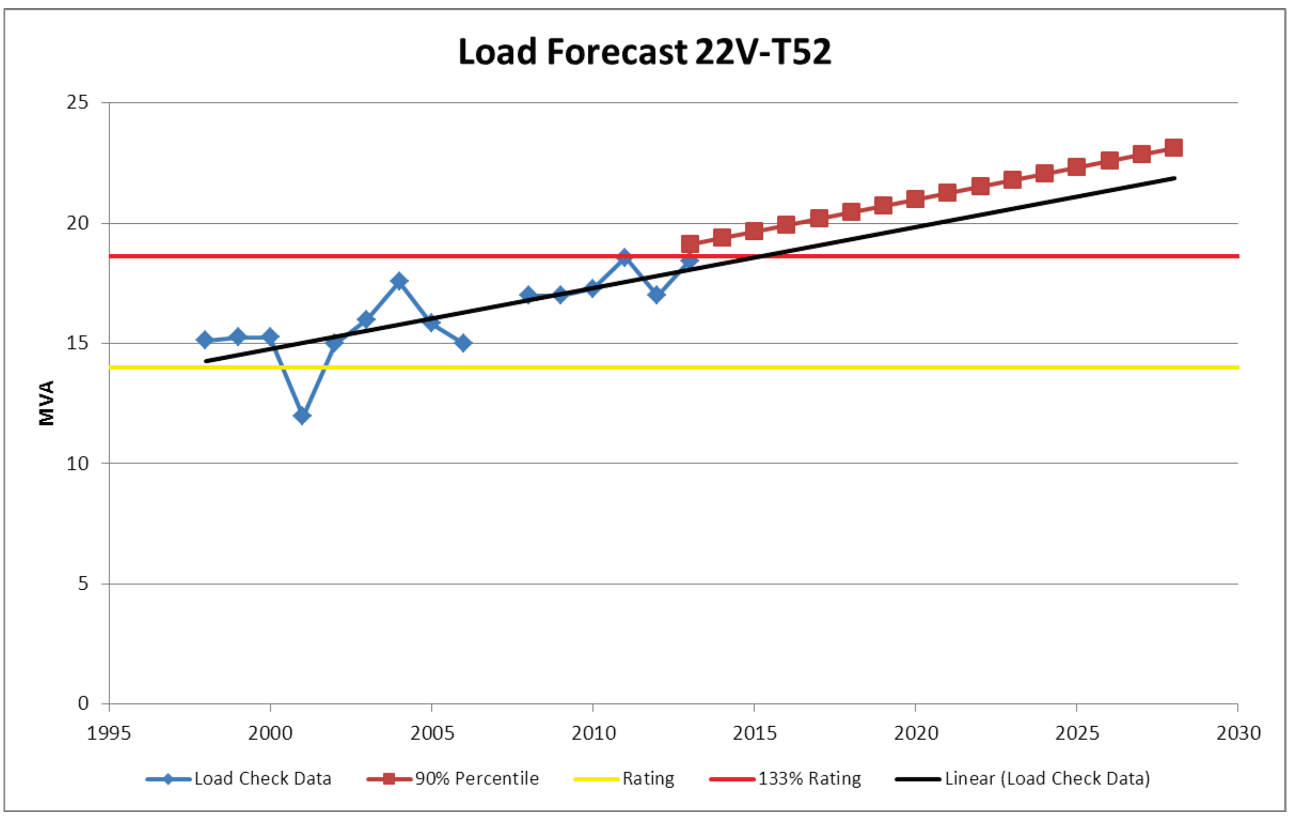


Figure 25 **22V-T52 Load Forecast**

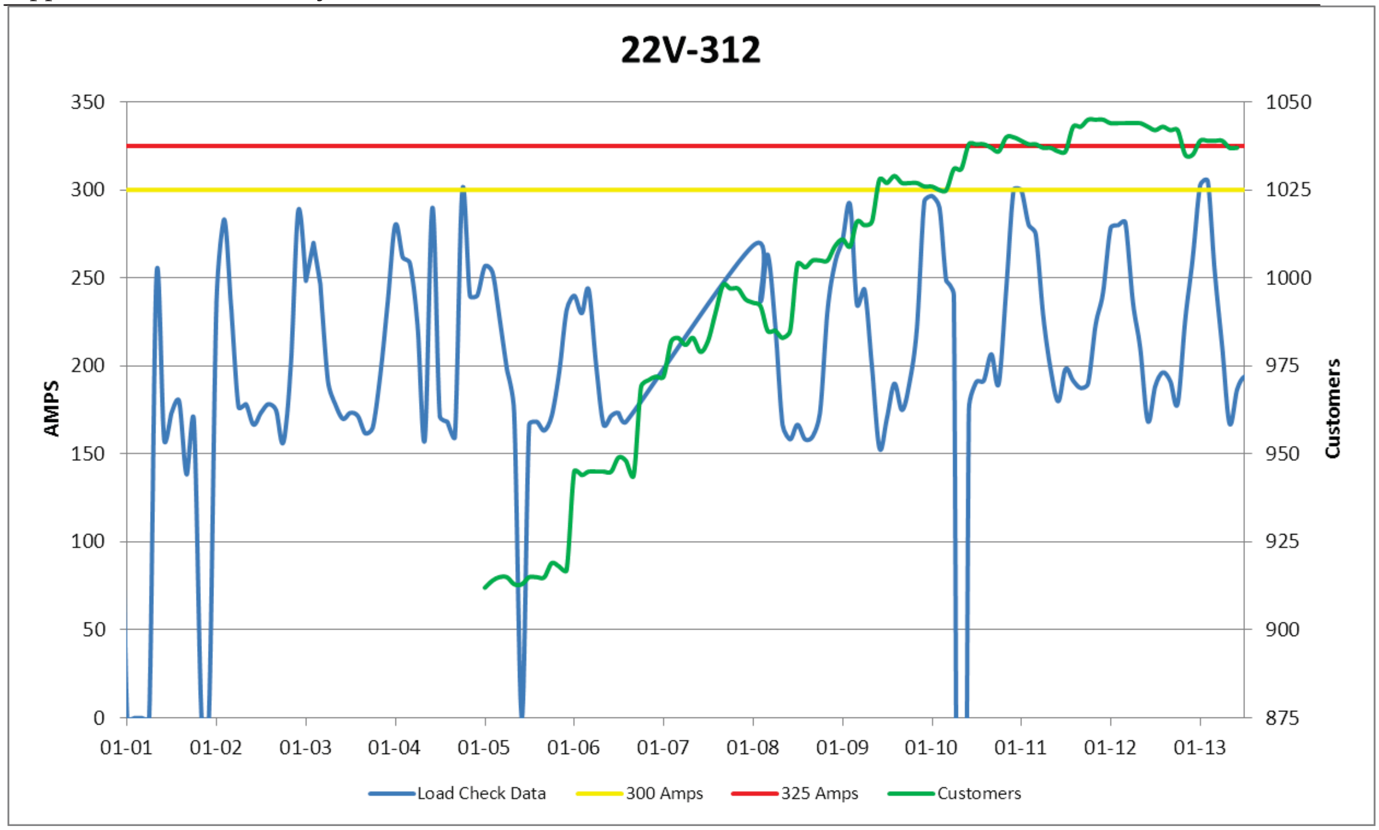


Figure 26 22V-312 Load History

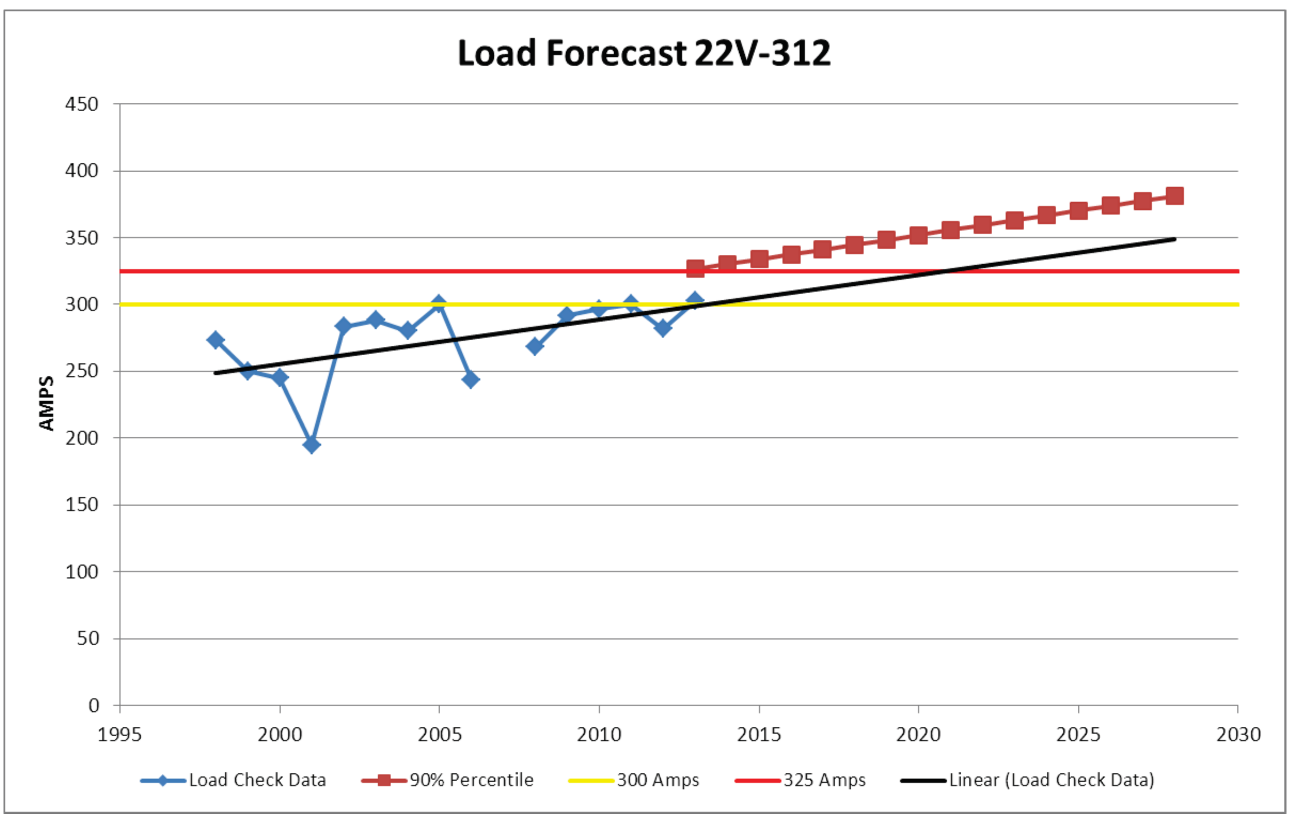


Figure 27 22V-312 Load Forecast

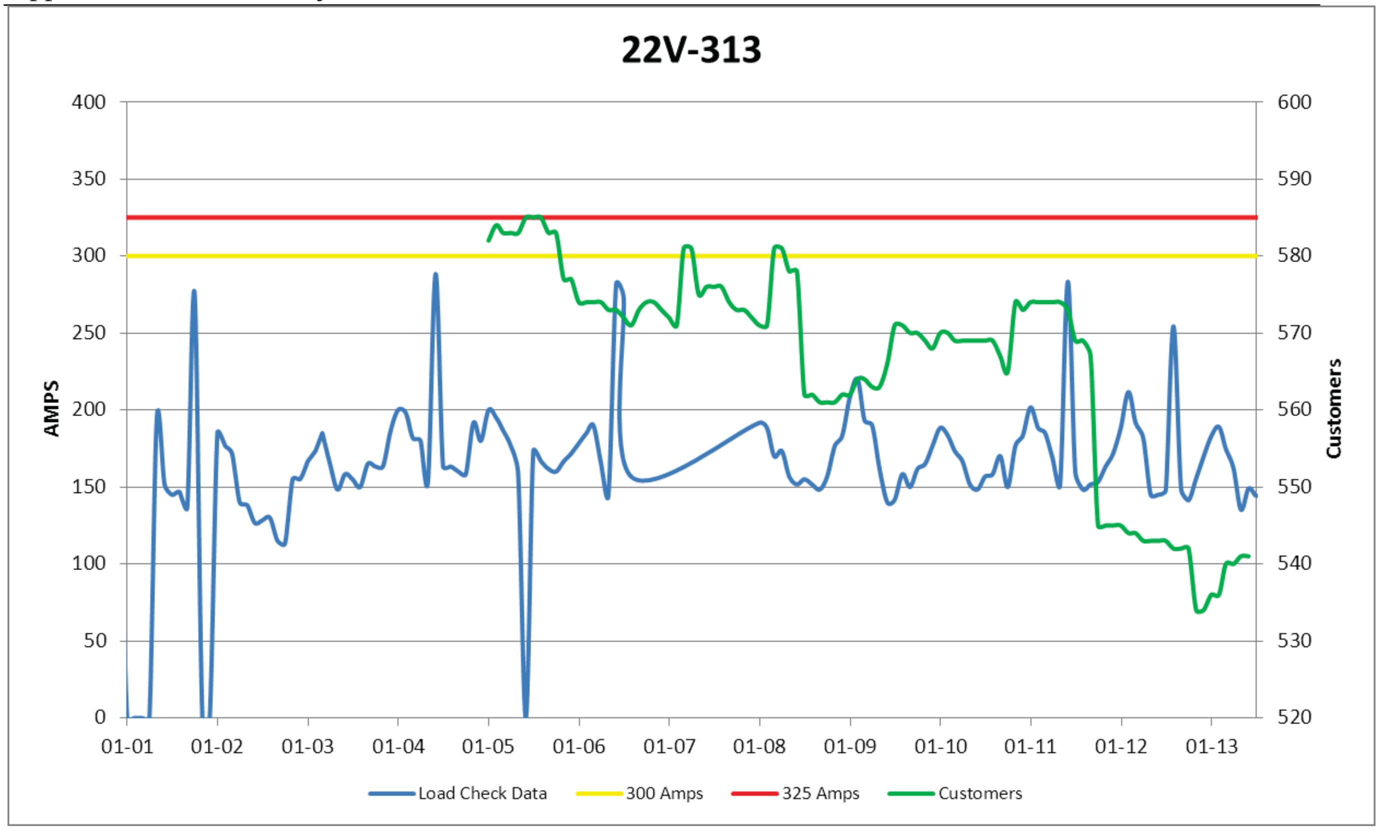


Figure 28 22V-313 Load History

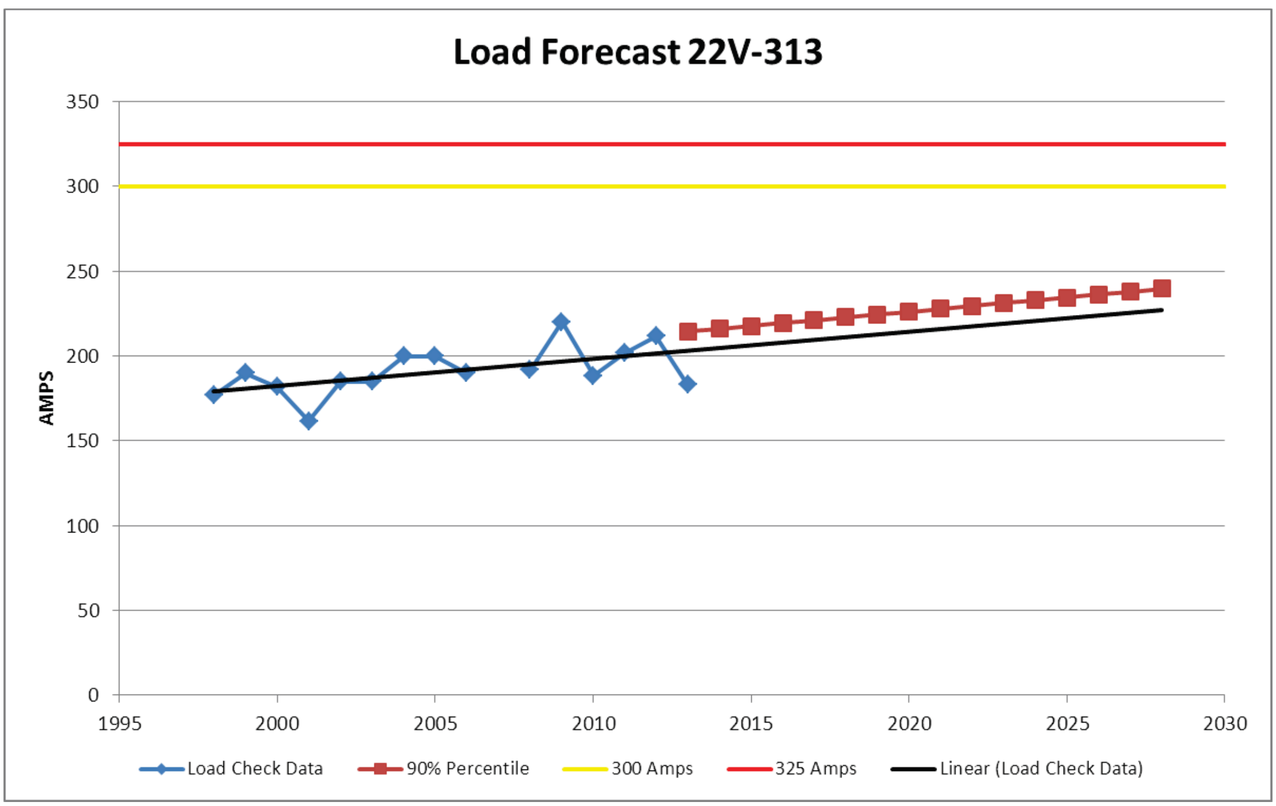


Figure 29 22V-313 Load Forecast

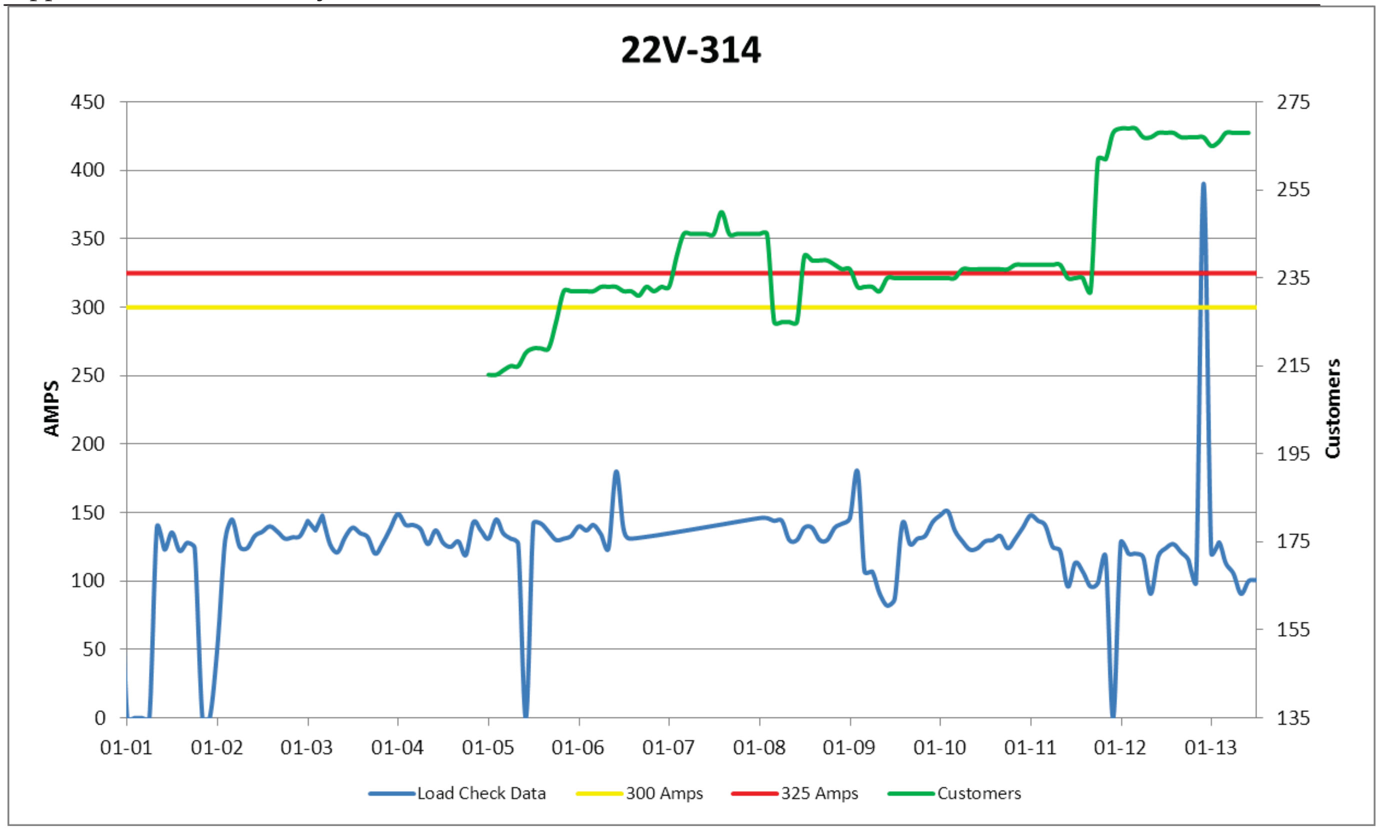


Figure 30 22V-314 Load History

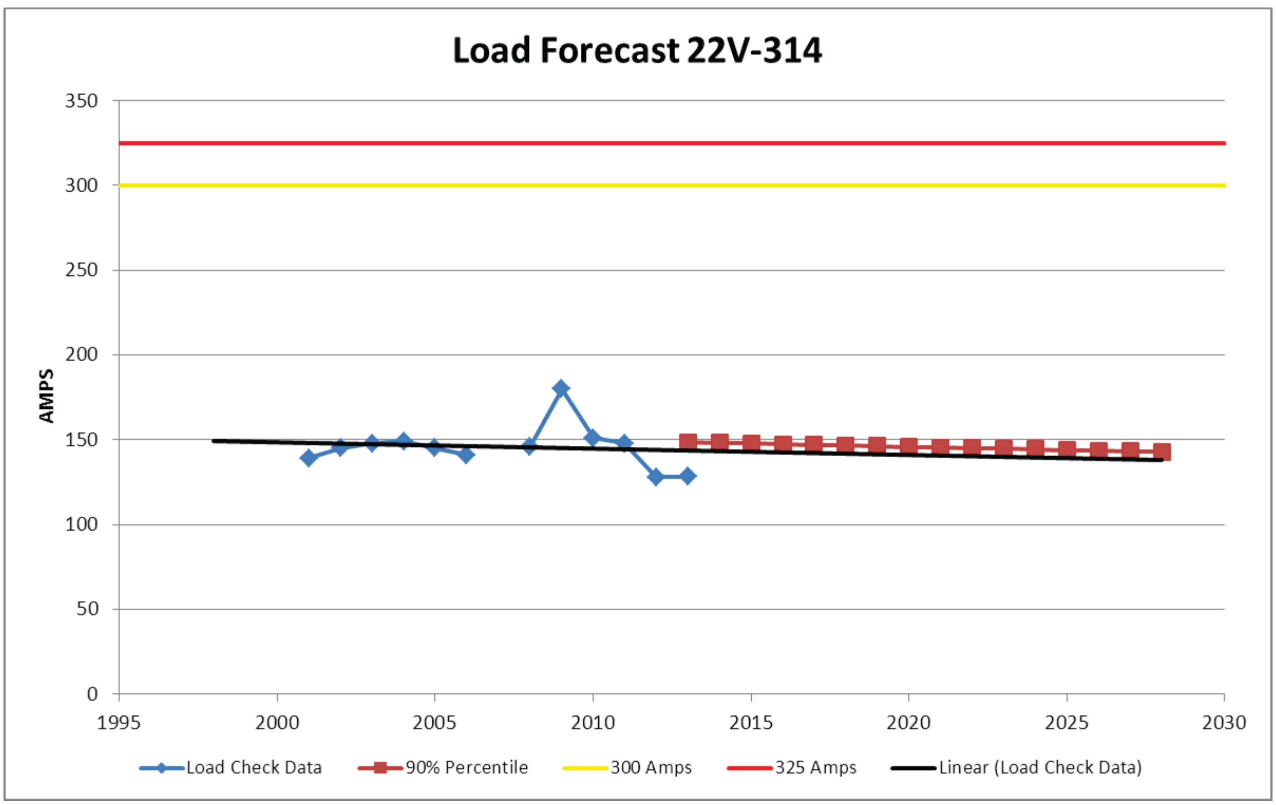


Figure 31 22V-314 Load Forecast

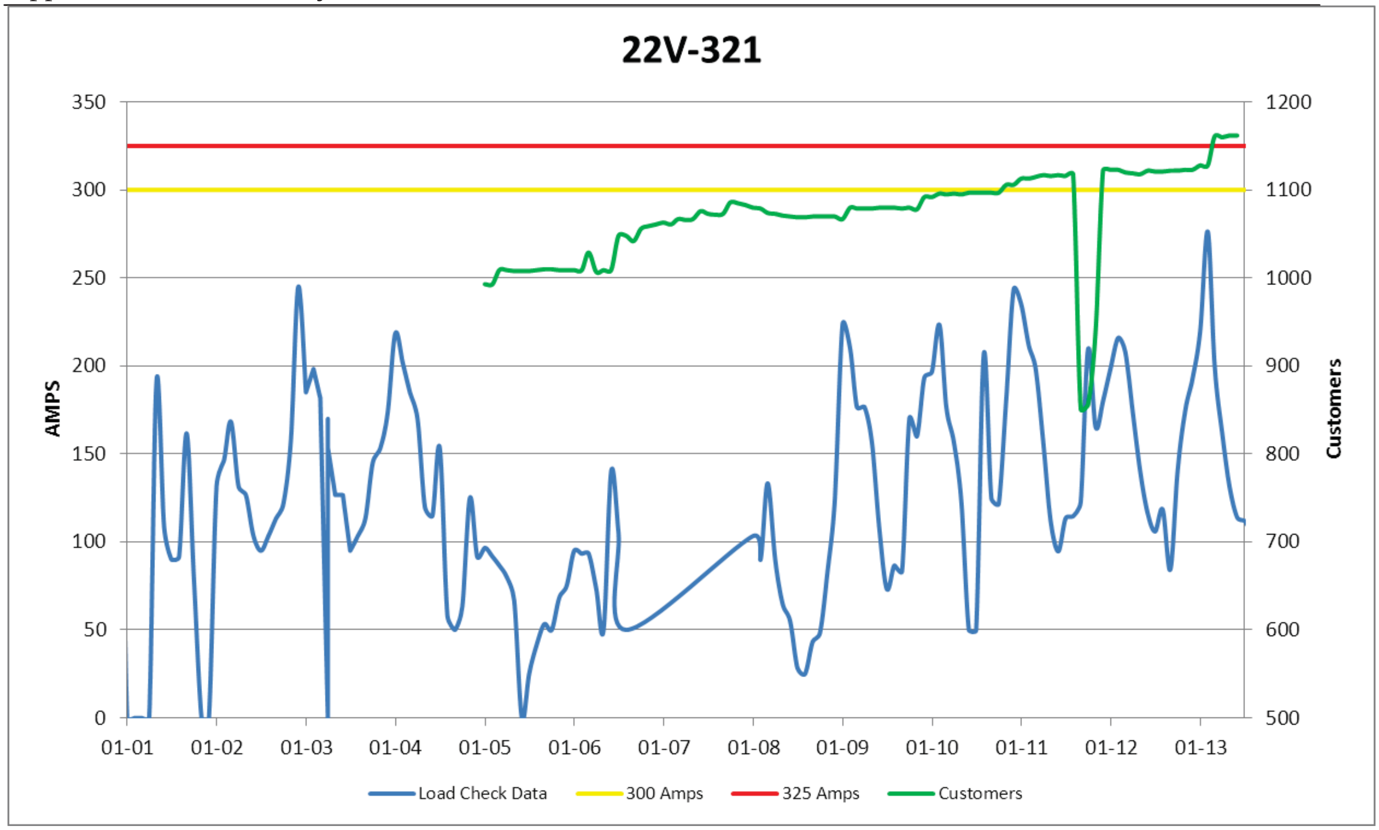


Figure 32 22V-321 Load History

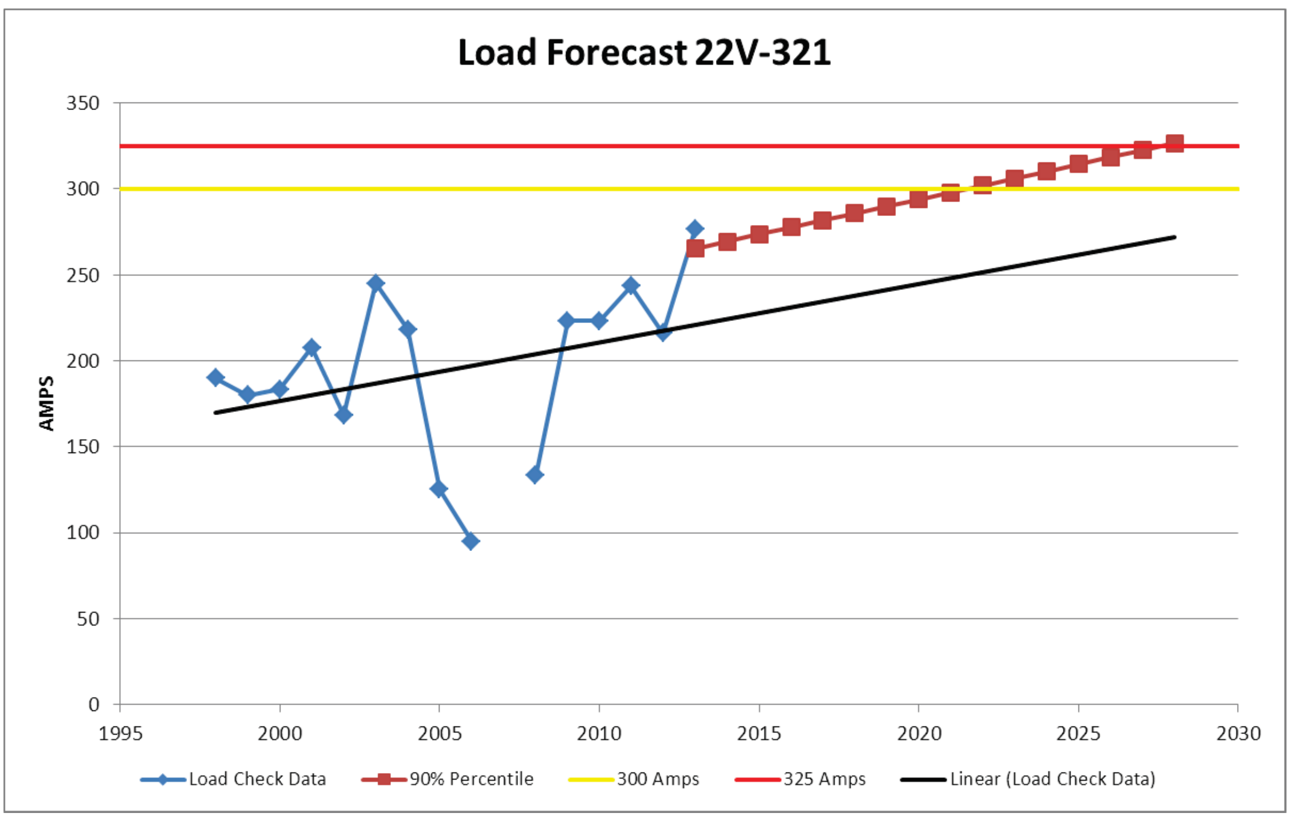


Figure 33 22V-321 Load Forecast

Appendix B: Load History and Forecast

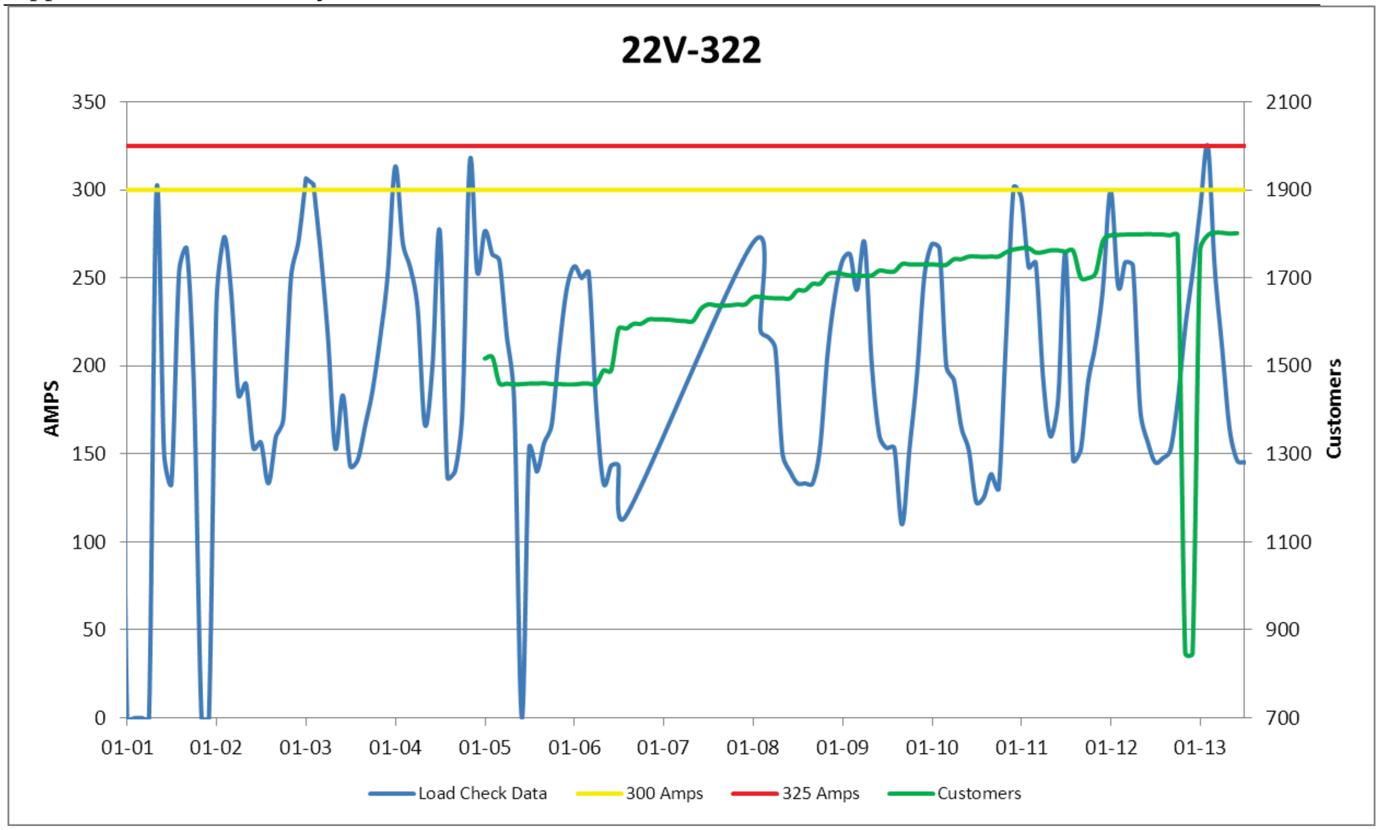


Figure 34 22V-322 Load History

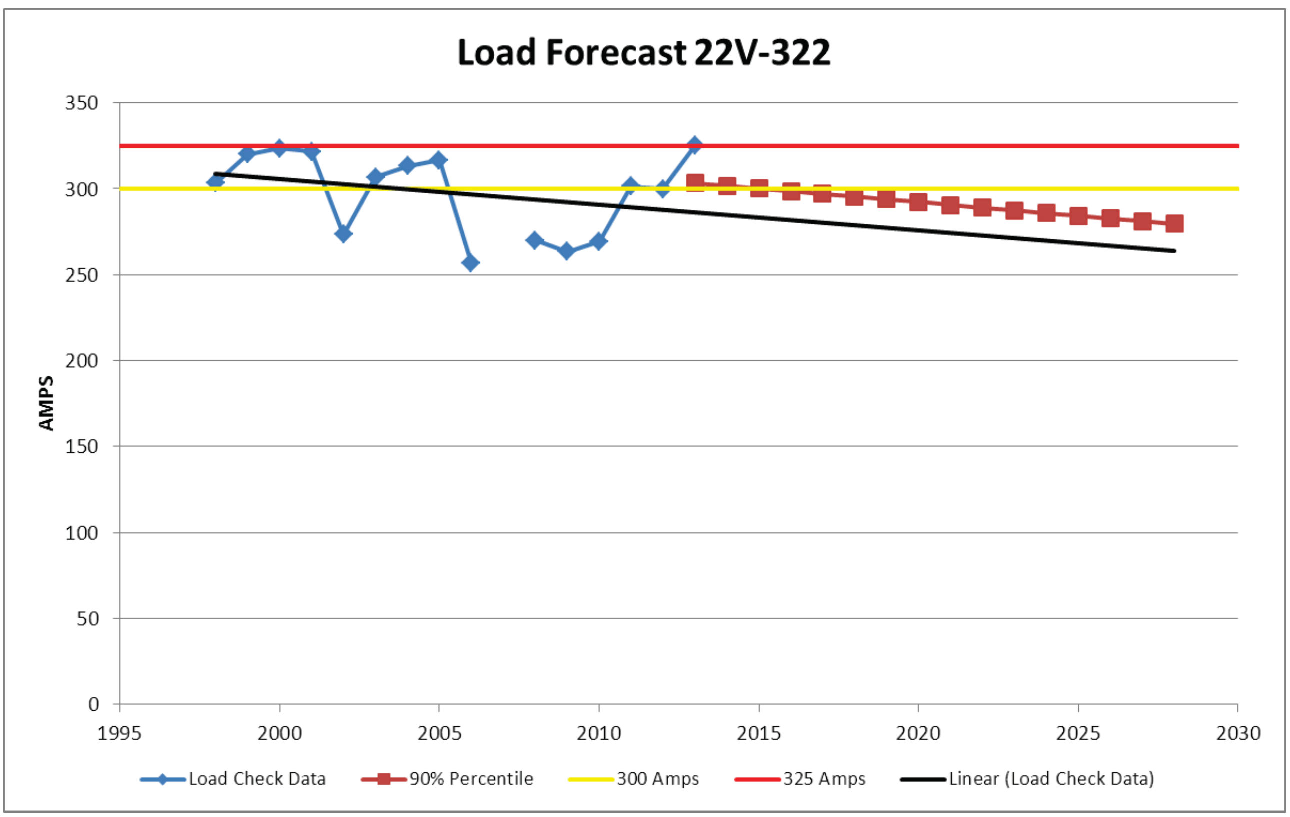


Figure 35 22V-322 Load Forecast

Appendix B: Load History and Forecast

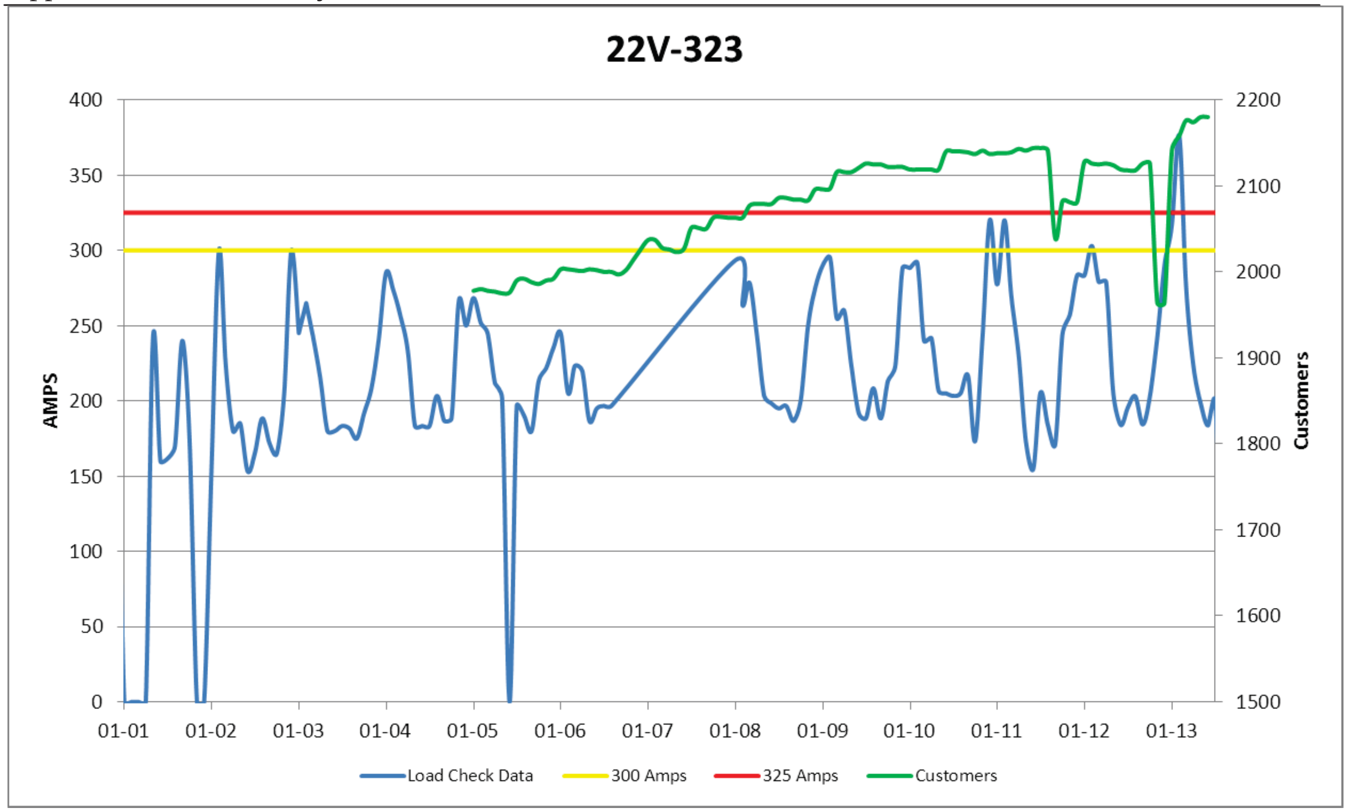


Figure 36 22V-323 Load History

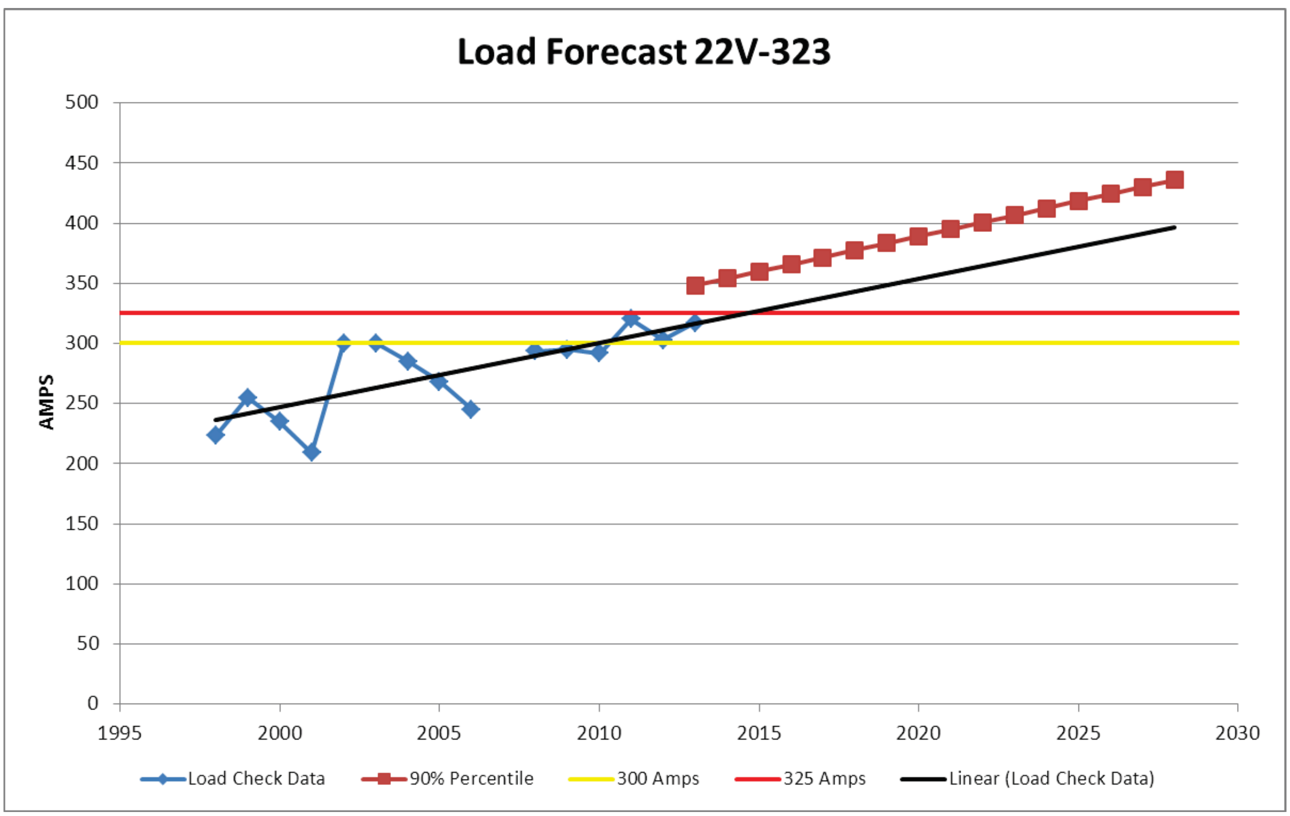


Figure 37 22V-323 Load Forecast

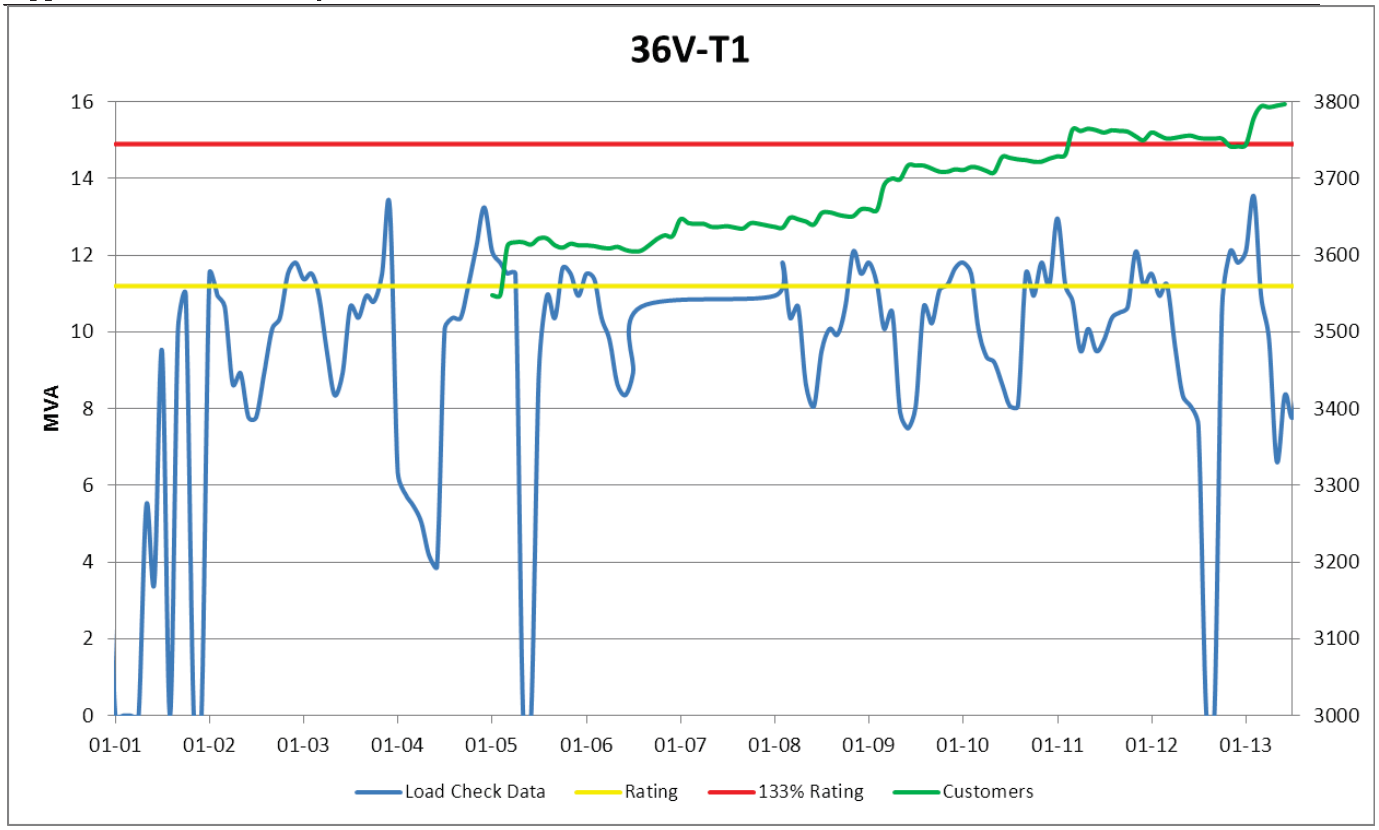


Figure 38 **36V-T1 Load History**

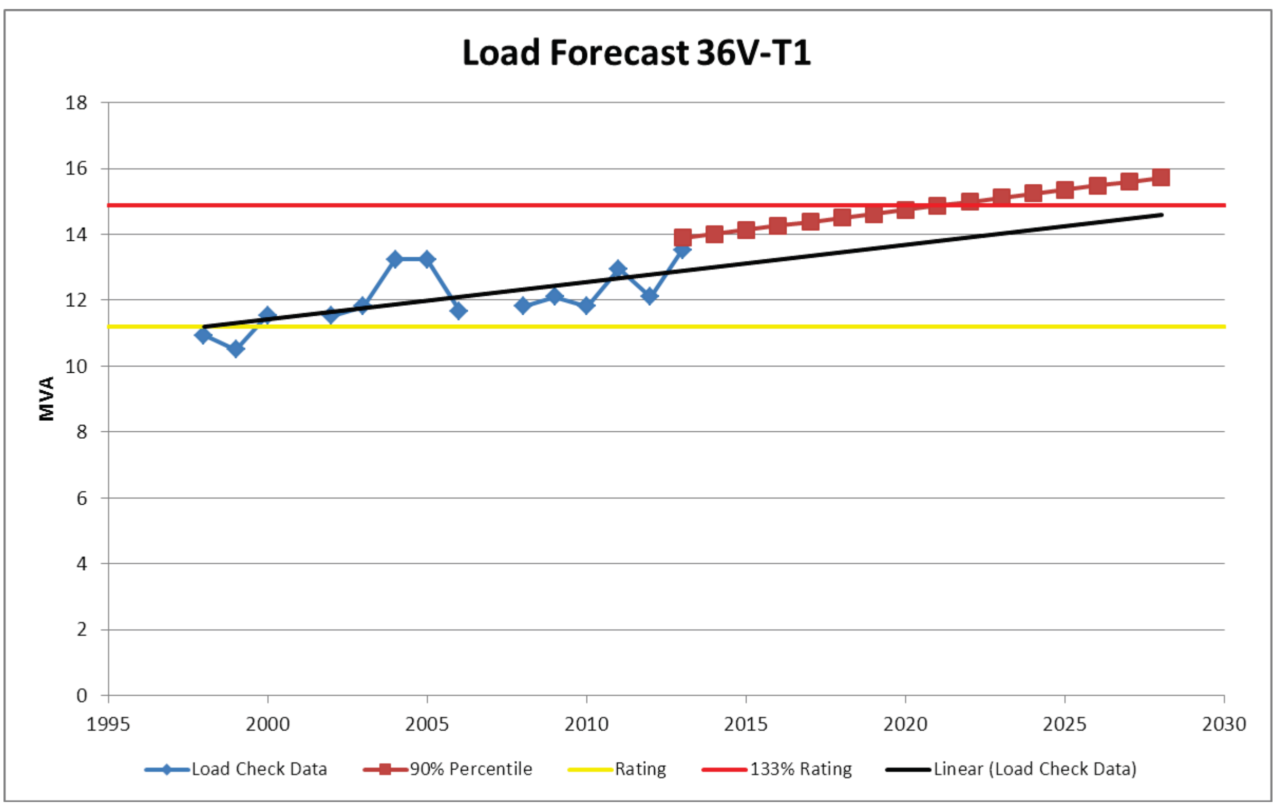


Figure 39 **36V-T1 Load Forecast**

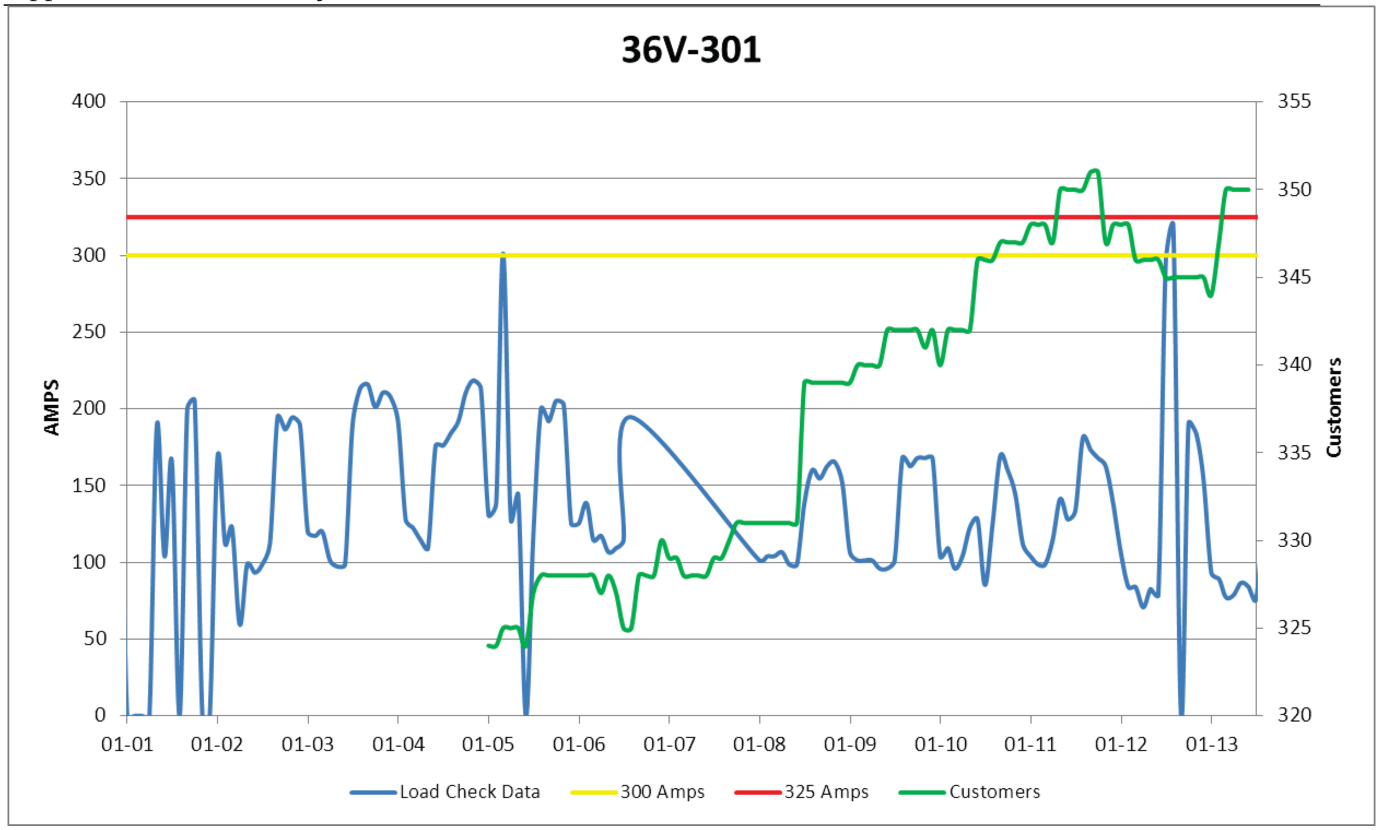


Figure 40 36V-301 Load History

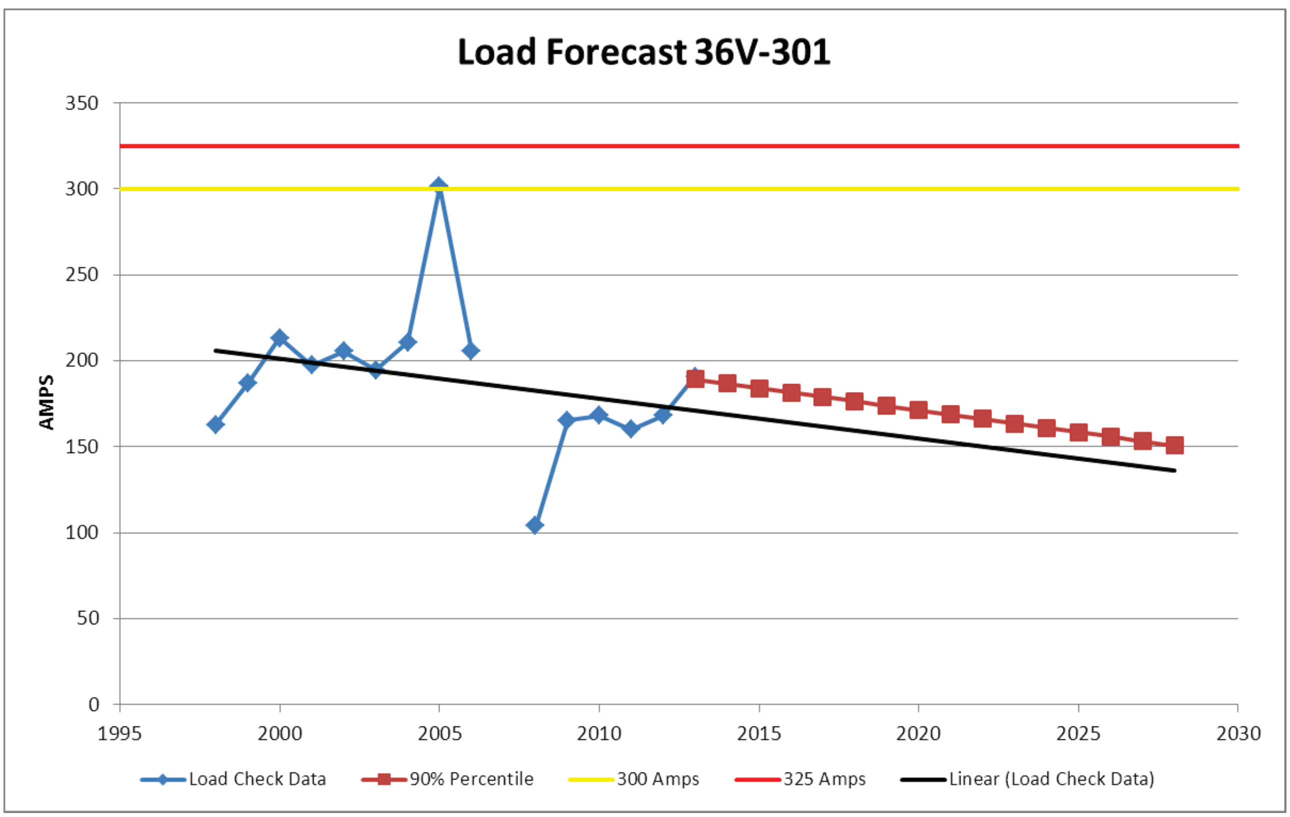


Figure 41 36V-301 Load Forecast

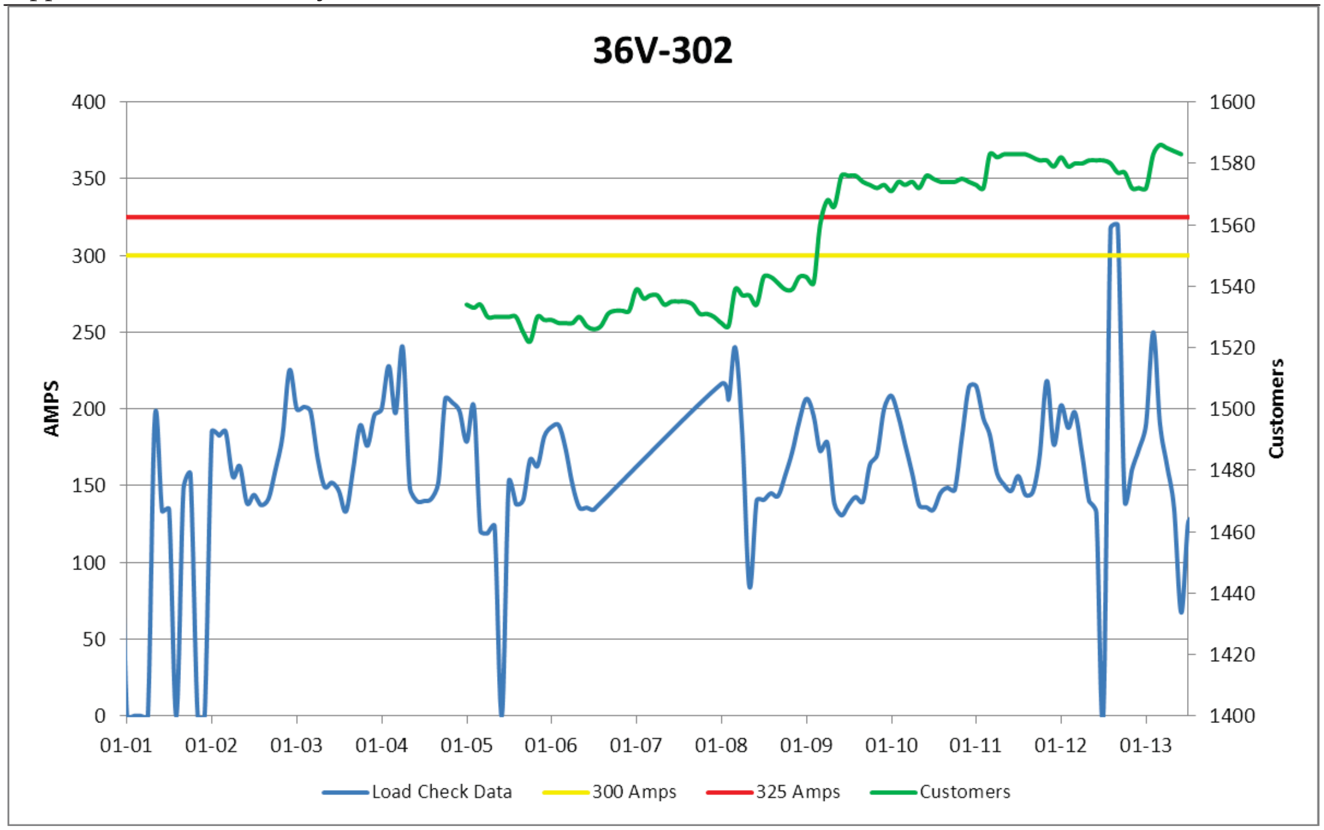


Figure 42 **36V-302 Load History**

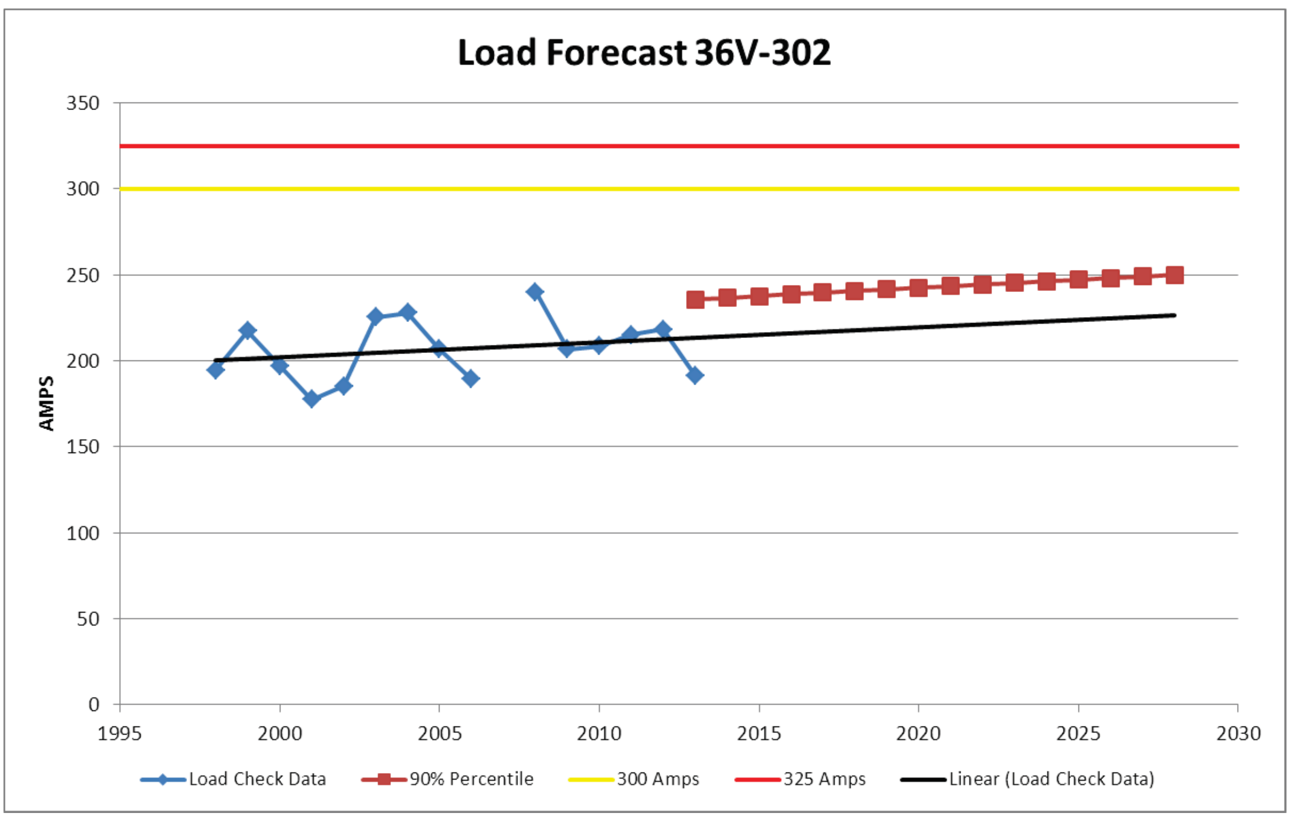


Figure 43 **36V-302 Load Forecast**

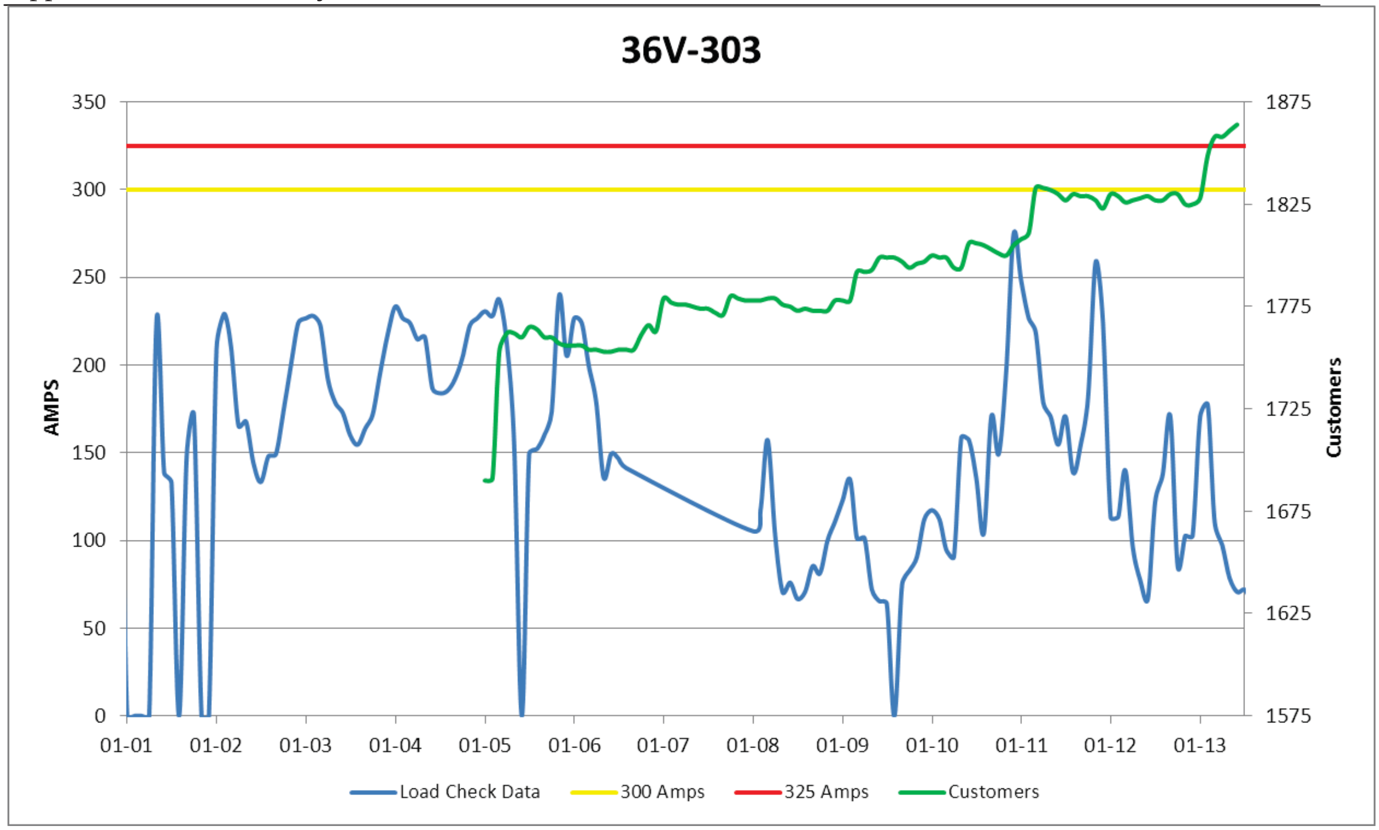


Figure 44 36V-303 Load History

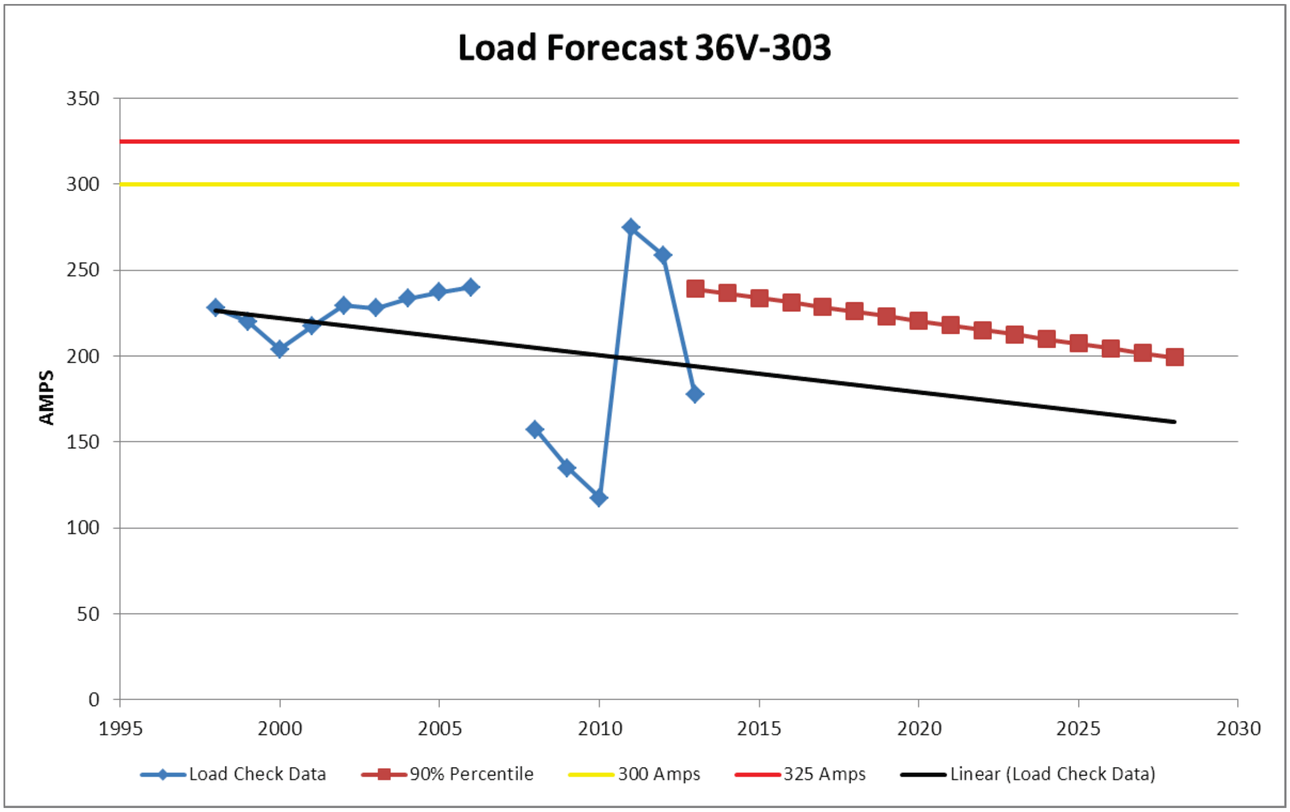


Figure 45 36V-303 Load Forecast

Appendix B: Load History and Forecast

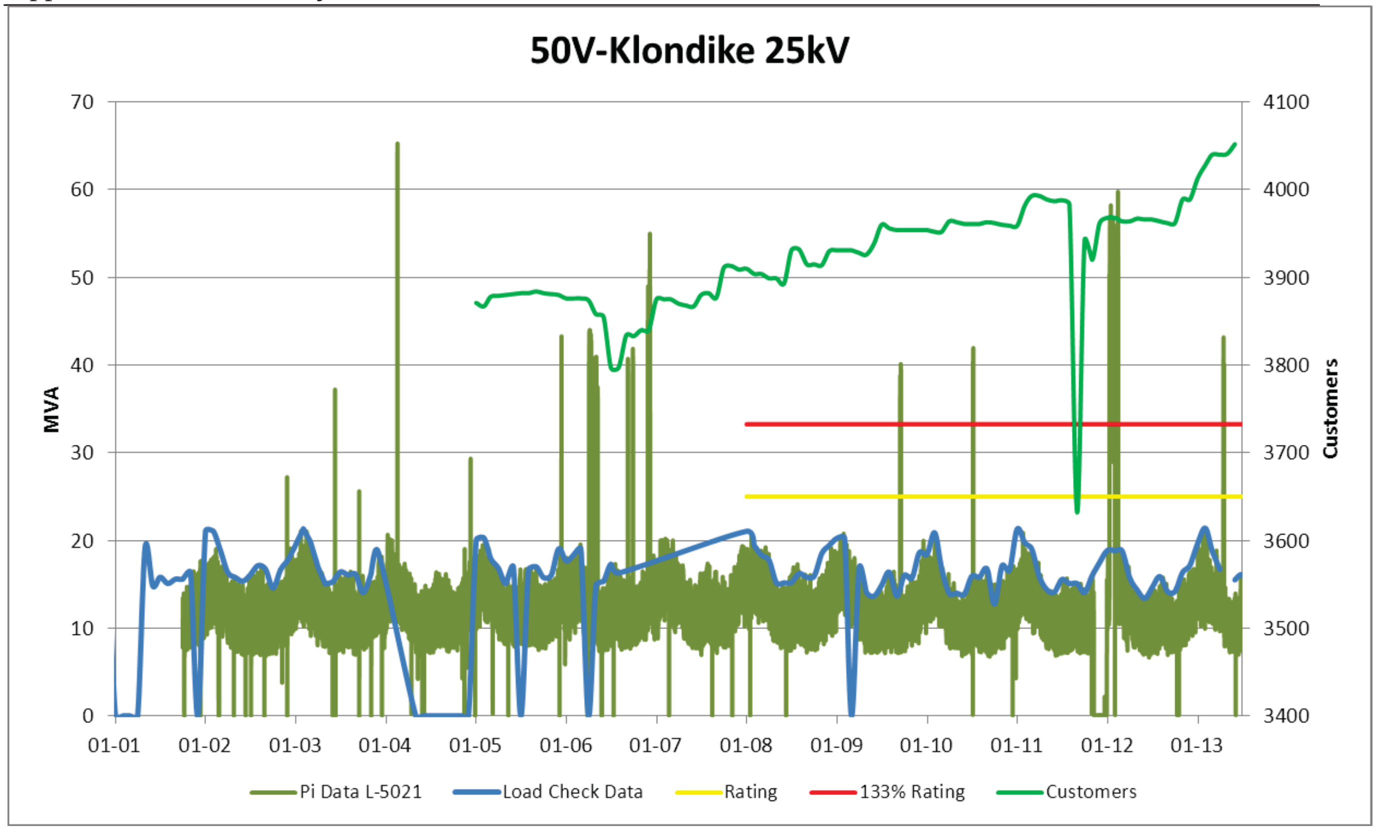


Figure 46 **50V-Klondike Load History**

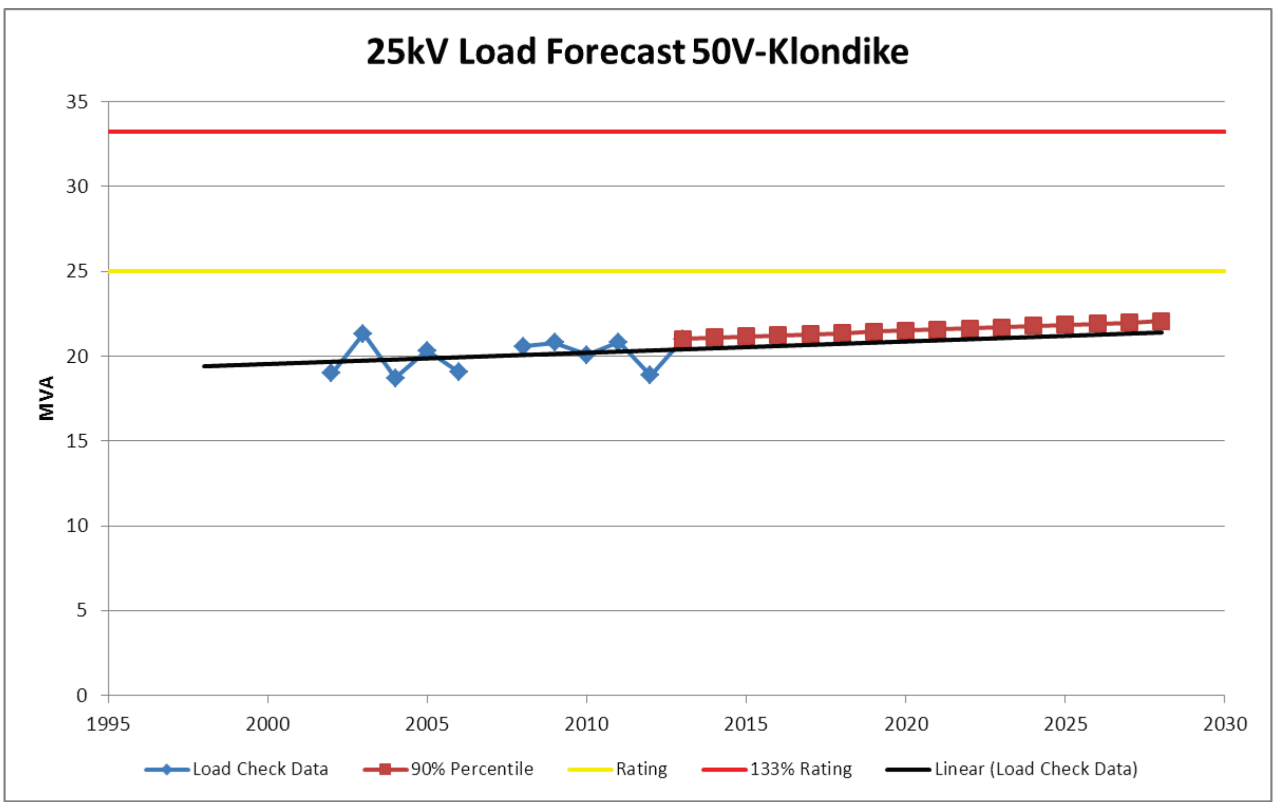


Figure 47 **50V-Klondike Load Forecast**

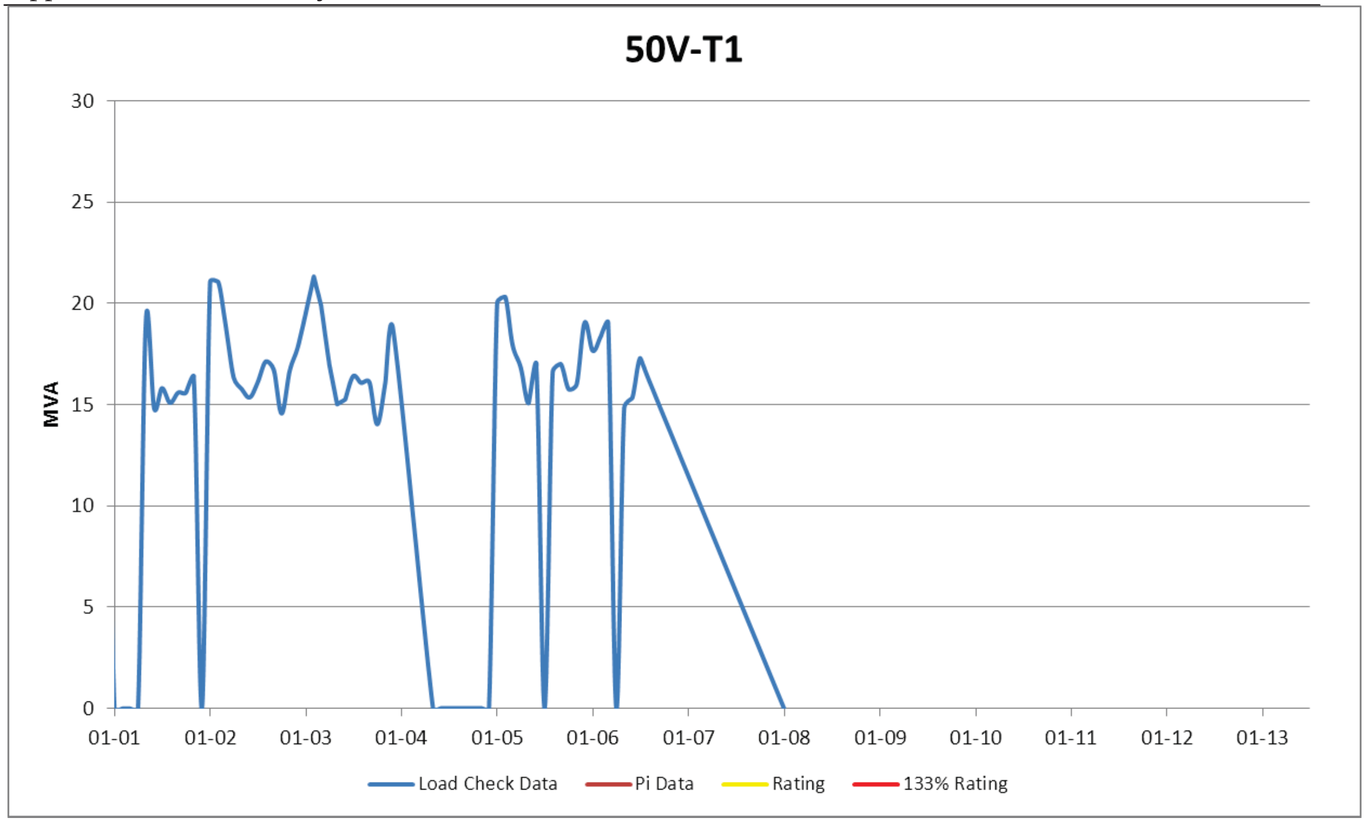


Figure 48 **50V-T1 Load History**

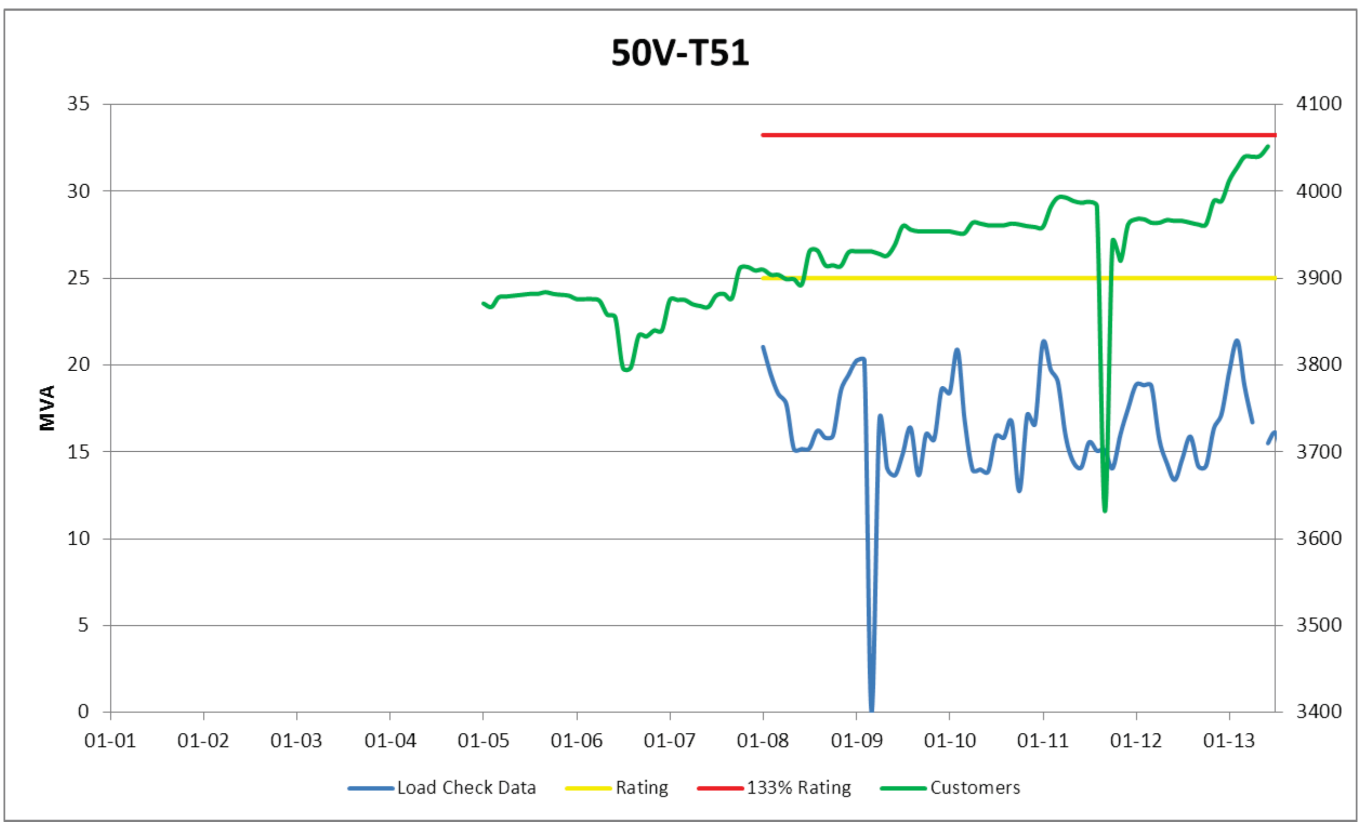


Figure 49 **50V-T51 Load History**

Appendix B: Load History and Forecast

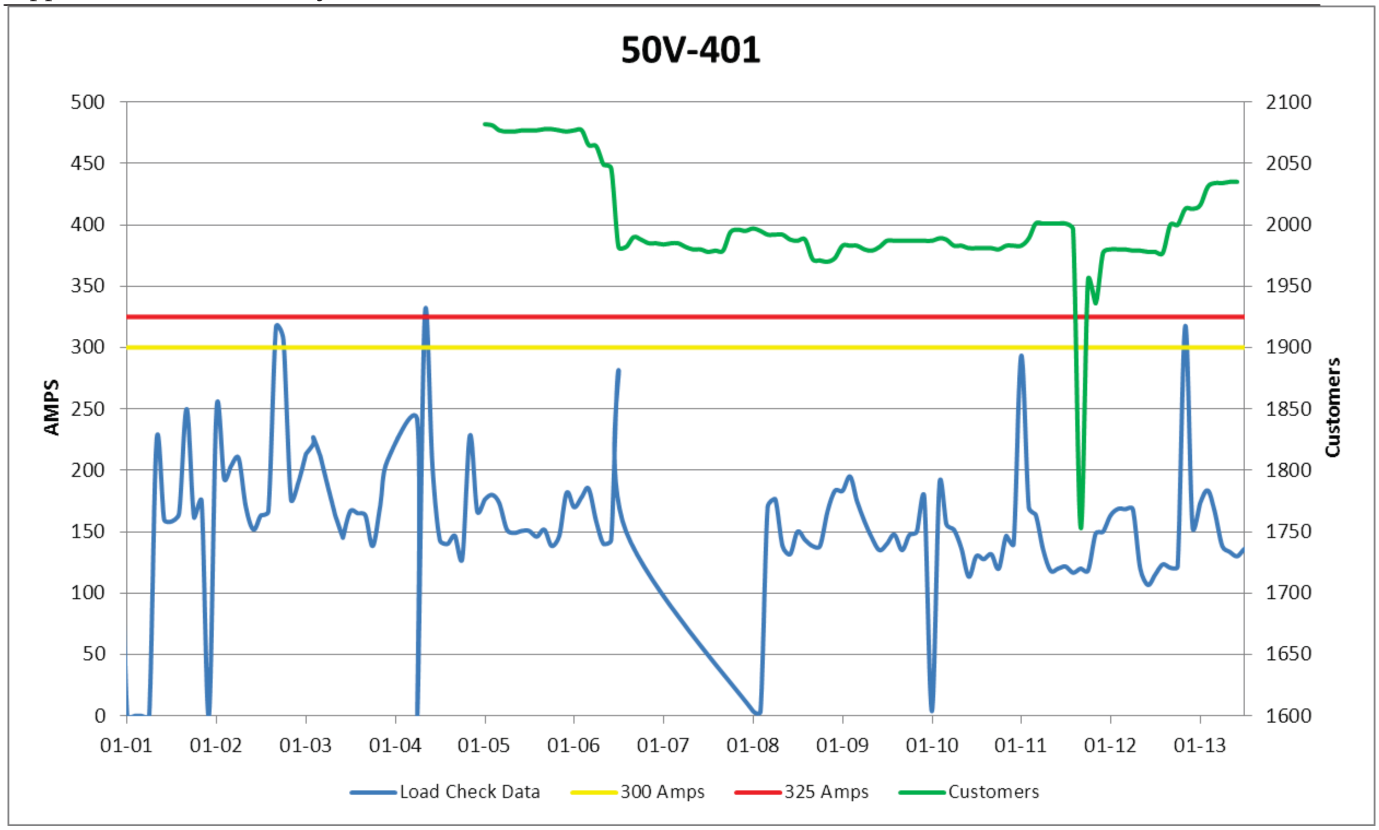


Figure 50 50V-401 Load History

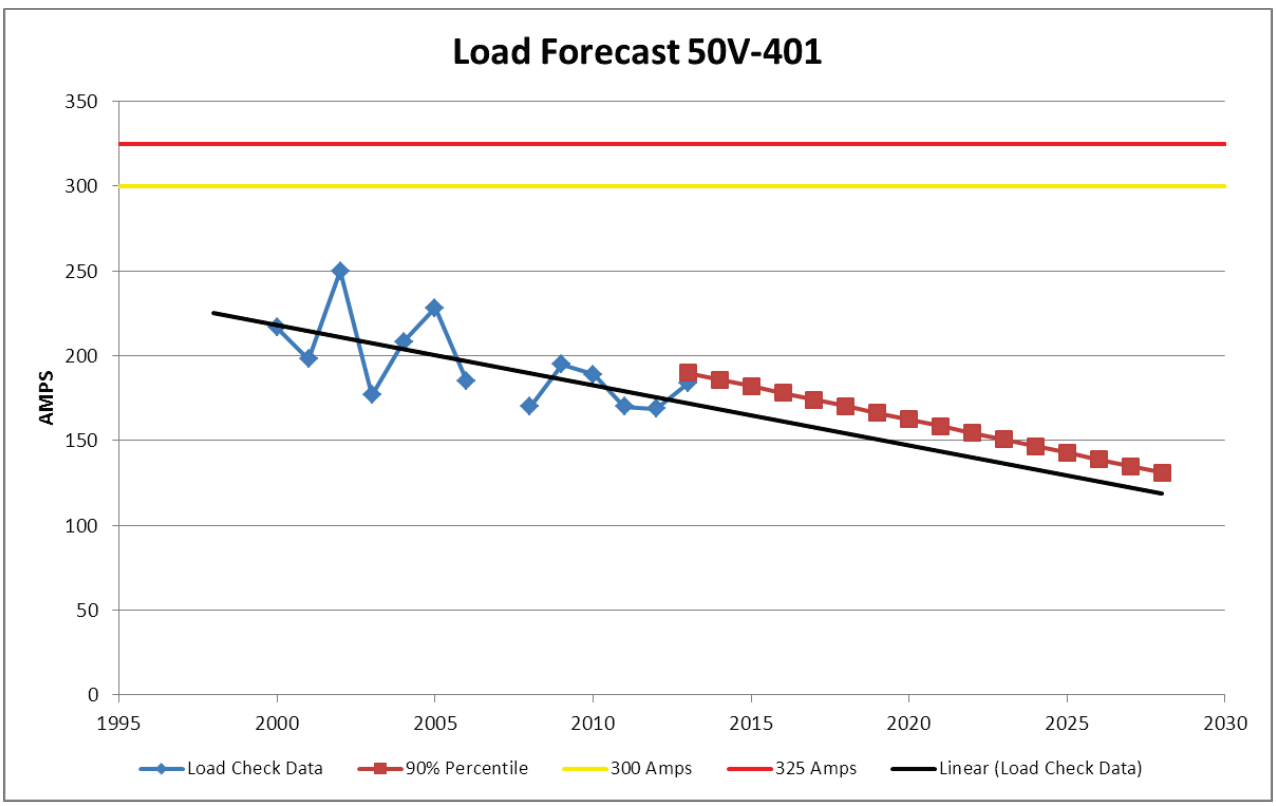


Figure 51 50V-401 Load Forecast

Appendix B: Load History and Forecast

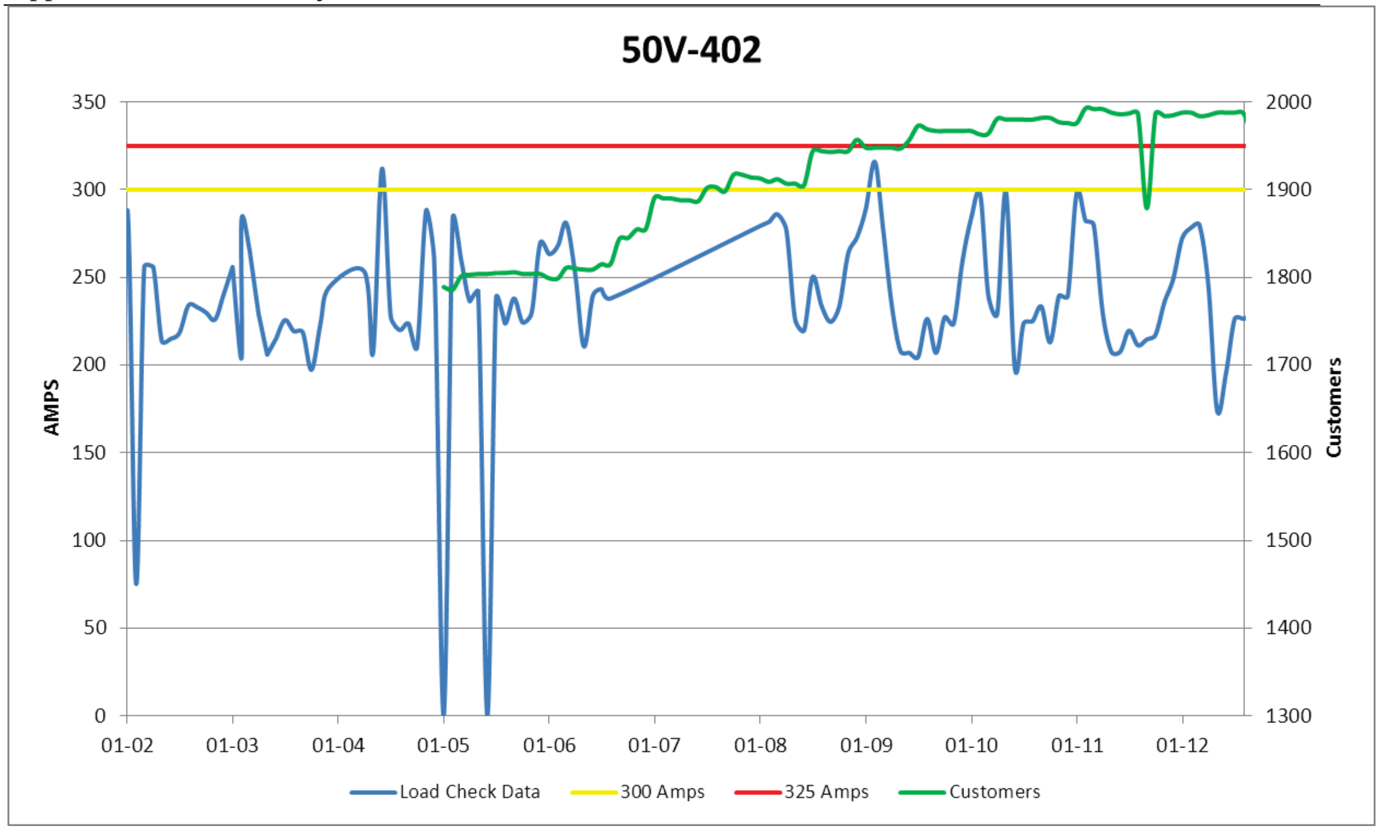


Figure 52 **50V-402 Load History**

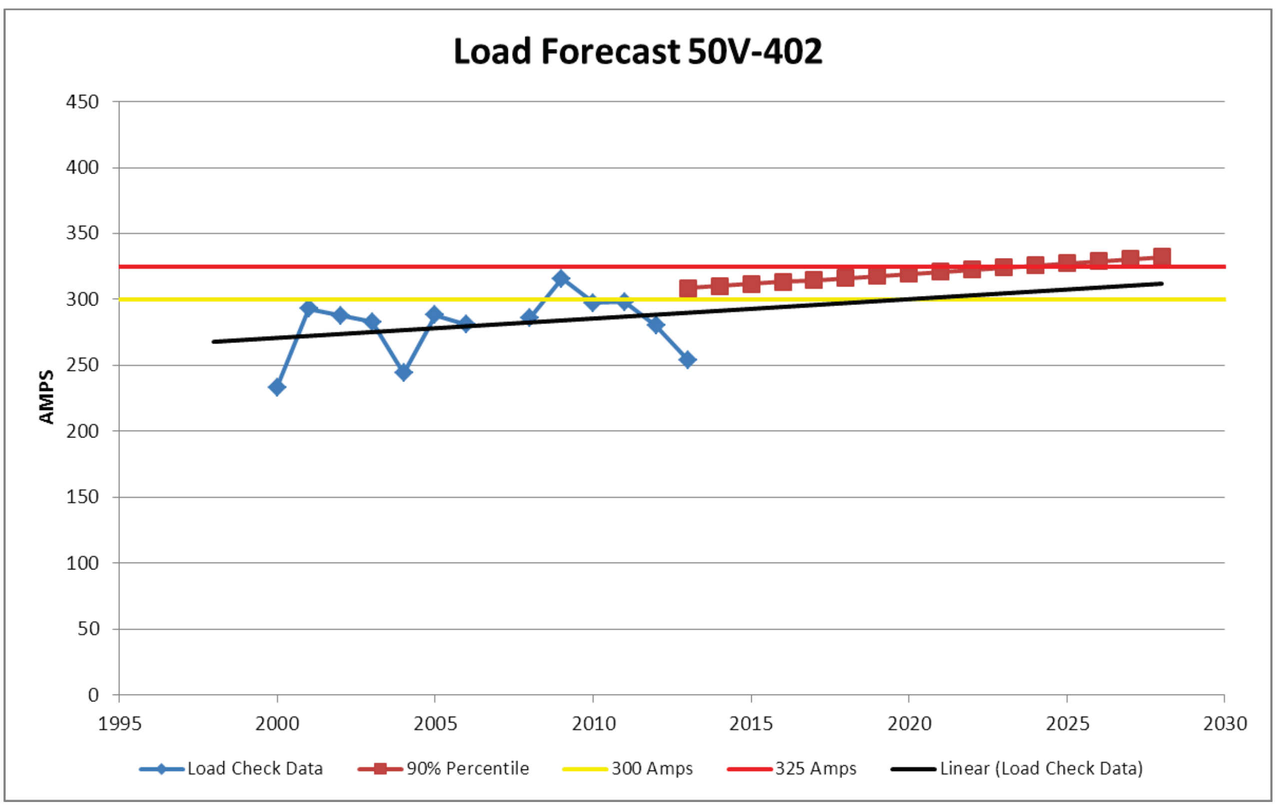


Figure 53 **50V-402 Load Forecast**

APPENDIX C

Economic Analysis

Summary of Alternatives

99V-Highbury Road
Summary of Alternatives

Nova Scotia POWER An Emera Company

Division :	Distribution Planning	**Date :**	17-May-13
Department :	Planning and Performance	**CI Number:**	
Originator :	James MacQueen	**Project No. :**	

	Alternative	After Tax WACC	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Replacement of 36V-Hilaton	6.48%	-1,282,883	3	-7.62%	0.0 years
B	Reconfiguration of 36V-Hilaton and 22V-New Minas Feeders	6.48%	-481,726	1	-7.52%	0.0 years
C	Reconfiguration of 36V-Hilaton with Load transfer to 50V-Klon	6.48%	-1,282,395	2	-7.83%	0.0 years
	0	NA	NA	NA	#NUM!	0.0 years

Recommendation :

This Economic Assessment Model recommends the reconfiguration of 22V-New Minas and 36V-Hilaton feeders.

Notes/Comments :

Replacement of 36V-Hilaton

This alternative will see the replcament of 36V-Hilaton. This will include:
- Replacement of 36V-T1 with a 10/12/15MVA transformer
- Creation of 4th feeder, at 36V-Hilaton
- Reconfiguration of 36V-Hilaton feeders

Reconfiguration of 36V-Hilaton and 22V-New Minas Feeders

This alternative will include:
- Creation of new express feeder from 99V-Highbury Road to Blecher Street
- Reconfiguration of existing feeders north of Cornwallis River

Reconfiguration of 36V-Hilaton with Load transfer to 50V-Klondoke

This alternative will see include:
- The addition of 25-12kV stepdowns
- Conversion of existing 4kV stepdowns

0

2013 EAM Rev-2.xls 5/17/2013

NPV Comparison

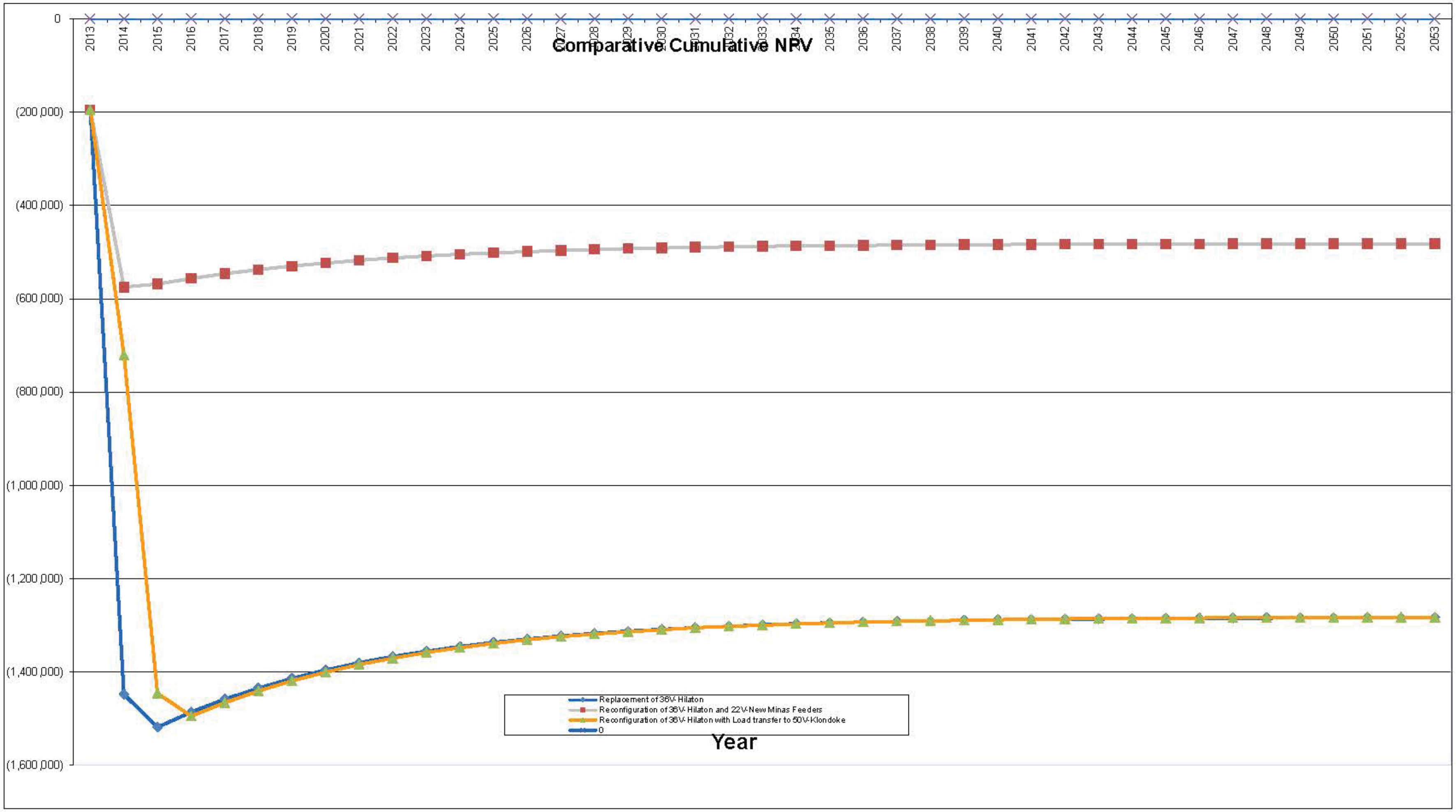


Figure 54 Economic Assessment Model NPV

Alternative 1- Replace 36V-T1

Table 7 Alternative 1- Replace 36V-T1

99V-Highbury Road
Replacement of 36V-Hilaton

Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2013	-	-	(195,000.0)	-	-	(195,000.0)	-	(195,000.0)	(195,000.000)	1.0	(195,000.0)
2014	-	-	#########	-	-	##########	-	(1,334,000.0)	(1,252,817.431)	0.9	(1,447,817.4)
2015	-	-	(100,000.0)	65,160.0	1,563,840.0	(100,000.0)	20,199.6	(79,800.4)	(70,383.196)	0.9	(1,518,200.6)
2016	-	-	-	125,107.2	1,438,732.8	-	38,783.2	38,783.2	32,124.758	0.8	(1,486,075.9)
2017	-	-	-	115,098.6	1,323,634.2	-	35,680.6	35,680.6	27,756.177	0.8	(1,458,319.7)
2018	-	-	-	105,890.7	1,217,743.4	-	32,826.1	32,826.1	23,981.671	0.7	(1,434,338.0)
2019	-	-	-	97,419.5	1,120,324.0	-	30,200.0	30,200.0	20,720.452	0.7	(1,413,617.6)
2020	-	-	-	89,625.9	1,030,698.0	-	27,784.0	27,784.0	17,902.720	0.6	(1,395,714.8)
2021	-	-	-	82,455.8	948,242.2	-	25,561.3	25,561.3	15,468.165	0.6	(1,380,246.7)
2022	-	-	-	75,859.4	872,382.8	-	23,516.4	23,516.4	13,364.680	0.6	(1,366,882.0)
2023	-	-	-	69,790.6	802,592.2	-	21,635.1	21,635.1	11,547.245	0.5	(1,355,334.8)
2024	-	-	-	64,207.4	738,384.8	-	19,904.3	19,904.3	9,976.958	0.5	(1,345,357.8)
2025	-	-	-	59,070.8	679,314.0	-	18,311.9	18,311.9	8,620.212	0.5	(1,336,737.6)
2026	-	-	-	54,345.1	624,968.9	-	16,847.0	16,847.0	7,447.967	0.4	(1,329,289.6)
2027	-	-	-	49,997.5	574,971.4	-	15,499.2	15,499.2	6,435.133	0.4	(1,322,854.5)
2028	-	-	-	45,997.7	528,973.7	-	14,259.3	14,259.3	5,560.032	0.4	(1,317,294.5)
2029	-	-	-	42,317.9	486,655.8	-	13,118.5	13,118.5	4,803.934	0.4	(1,312,490.5)
2030	-	-	-	38,932.5	447,723.3	-	12,069.1	12,069.1	4,150.657	0.3	(1,308,339.9)
2031	-	-	-	35,817.9	411,905.5	-	11,103.5	11,103.5	3,586.218	0.3	(1,304,753.6)
2032	-	-	-	32,952.4	378,953.0	-	10,215.3	10,215.3	3,098.535	0.3	(1,301,655.1)
2033	-	-	-	30,316.2	348,636.8	-	9,398.0	9,398.0	2,677.172	0.3	(1,298,977.9)
2034	-	-	-	27,890.9	320,745.8	-	8,646.2	8,646.2	2,313.108	0.3	(1,296,664.8)
2035	-	-	-	25,659.7	295,086.2	-	7,954.5	7,954.5	1,998.554	0.3	(1,294,666.3)
2036	-	-	-	23,606.9	271,479.3	-	7,318.1	7,318.1	1,726.774	0.2	(1,292,939.5)
2037	-	-	-	21,718.3	249,760.9	-	6,732.7	6,732.7	1,491.954	0.2	(1,291,447.6)
2038	-	-	-	19,980.9	229,780.1	-	6,194.1	6,194.1	1,289.066	0.2	(1,290,158.5)
2039	-	-	-	18,382.4	211,397.7	-	5,698.5	5,698.5	1,113.768	0.2	(1,289,044.7)
2040	-	-	-	16,911.8	194,485.8	-	5,242.7	5,242.7	962.309	0.2	(1,288,082.4)
2041	-	-	-	15,558.9	178,927.0	-	4,823.2	4,823.2	831.447	0.2	(1,287,251.0)
2042	-	-	-	14,314.2	164,612.8	-	4,437.4	4,437.4	718.380	0.2	(1,286,532.6)
2043	-	-	-	13,169.0	151,443.8	-	4,082.4	4,082.4	620.689	0.2	(1,285,911.9)
2044	-	-	-	12,115.5	139,328.3	-	3,755.8	3,755.8	536.283	0.1	(1,285,375.6)
2045	-	-	-	11,146.3	128,182.0	-	3,455.3	3,455.3	463.355	0.1	(1,284,912.3)
2046	-	-	-	10,254.6	117,927.5	-	3,178.9	3,178.9	400.344	0.1	(1,284,511.9)
2047	-	-	-	9,434.2	108,493.3	-	2,924.6	2,924.6	345.902	0.1	(1,284,166.0)
2048	-	-	-	8,679.5	99,813.8	-	2,690.6	2,690.6	298.864	0.1	(1,283,867.1)
2049	-	-	-	7,985.1	91,828.7	-	2,475.4	2,475.4	258.222	0.1	(1,283,608.9)
2050	-	-	-	7,346.3	84,482.4	-	2,277.4	2,277.4	223.107	0.1	(1,283,385.8)
2051	-	-	-	6,758.6	77,723.8	-	2,095.2	2,095.2	192.767	0.1	(1,283,193.0)
2052	-	-	-	6,217.9	71,505.9	-	1,927.6	1,927.6	166.553	0.1	(1,283,026.5)
2053	-	-	-	5,720.5	65,785.4	-	1,773.3	1,773.3	143.904	0.1	(1,282,882.6)
Total	-	-	#########	1,563,214.6		##########	484,596.5	(1,144,403.5)	(1,282,882.6)		

Alternative 2- 99V-Highbury, 22V-New Minas, and 36V-Hillaton Load Transfers

Table 8 Alternative 2- 12kV Load Transfers

99V-Highbury Road
Reconfiguration of 36V-Hilaton and 22V-New Minas Feeders

Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2013	-	-	(195,000.0)	-	-	(195,000.0)	-	(195,000.0)	(195,000.000)	1.0	(195,000.0)
2014	-	-	(404,500.0)	-	-	(404,500.0)	-	(404,500.0)	(379,883.546)	0.9	(574,883.5)
2015	-	-	-	23,980.0	599,500.0	-	7,433.8	7,433.8	6,556.541	0.9	(568,327.0)
2016	-	-	-	46,041.6	529,478.4	-	14,272.9	14,272.9	11,822.463	0.8	(556,504.5)
2017	-	-	-	42,358.3	487,120.1	-	13,131.1	13,131.1	10,214.750	0.8	(546,289.8)
2018	-	-	-	38,969.6	448,150.5	-	12,080.6	12,080.6	8,825.667	0.7	(537,464.1)
2019	-	-	-	35,852.0	412,298.5	-	11,114.1	11,114.1	7,625.482	0.7	(529,838.6)
2020	-	-	-	32,983.9	379,314.6	-	10,225.0	10,225.0	6,588.509	0.6	(523,250.1)
2021	-	-	-	30,345.2	348,969.4	-	9,407.0	9,407.0	5,692.551	0.6	(517,557.6)
2022	-	-	-	27,917.6	321,051.9	-	8,654.4	8,654.4	4,918.432	0.6	(512,639.2)
2023	-	-	-	25,684.2	295,367.7	-	7,962.1	7,962.1	4,249.584	0.5	(508,389.6)
2024	-	-	-	23,629.4	271,738.3	-	7,325.1	7,325.1	3,671.692	0.5	(504,717.9)
2025	-	-	-	21,739.1	249,999.2	-	6,739.1	6,739.1	3,172.386	0.5	(501,545.5)
2026	-	-	-	19,999.9	229,999.3	-	6,200.0	6,200.0	2,740.980	0.4	(498,804.5)
2027	-	-	-	18,399.9	211,599.4	-	5,704.0	5,704.0	2,368.239	0.4	(496,436.3)
2028	-	-	-	16,927.9	194,671.4	-	5,247.7	5,247.7	2,046.187	0.4	(494,390.1)
2029	-	-	-	15,573.7	179,097.7	-	4,827.9	4,827.9	1,767.930	0.4	(492,622.2)
2030	-	-	-	14,327.8	164,769.9	-	4,441.6	4,441.6	1,527.513	0.3	(491,094.6)
2031	-	-	-	13,181.6	151,588.3	-	4,086.3	4,086.3	1,319.790	0.3	(489,774.8)
2032	-	-	-	12,127.1	139,461.2	-	3,759.4	3,759.4	1,140.314	0.3	(488,634.5)
2033	-	-	-	11,156.9	128,304.3	-	3,458.6	3,458.6	985.245	0.3	(487,649.3)
2034	-	-	-	10,264.3	118,040.0	-	3,181.9	3,181.9	851.264	0.3	(486,798.0)
2035	-	-	-	9,443.2	108,596.8	-	2,927.4	2,927.4	735.502	0.3	(486,062.5)
2036	-	-	-	8,687.7	99,909.0	-	2,693.2	2,693.2	635.483	0.2	(485,427.0)
2037	-	-	-	7,992.7	91,916.3	-	2,477.7	2,477.7	549.065	0.2	(484,878.0)
2038	-	-	-	7,353.3	84,563.0	-	2,279.5	2,279.5	474.398	0.2	(484,403.6)
2039	-	-	-	6,765.0	77,798.0	-	2,097.2	2,097.2	409.886	0.2	(483,993.7)
2040	-	-	-	6,223.8	71,574.1	-	1,929.4	1,929.4	354.146	0.2	(483,639.5)
2041	-	-	-	5,725.9	65,848.2	-	1,775.0	1,775.0	305.987	0.2	(483,333.6)
2042	-	-	-	5,267.9	60,580.3	-	1,633.0	1,633.0	264.376	0.2	(483,069.2)
2043	-	-	-	4,846.4	55,733.9	-	1,502.4	1,502.4	228.424	0.2	(482,840.8)
2044	-	-	-	4,458.7	51,275.2	-	1,382.2	1,382.2	197.361	0.1	(482,643.4)
2045	-	-	-	4,102.0	47,173.2	-	1,271.6	1,271.6	170.523	0.1	(482,472.9)
2046	-	-	-	3,773.9	43,399.3	-	1,169.9	1,169.9	147.334	0.1	(482,325.5)
2047	-	-	-	3,471.9	39,927.4	-	1,076.3	1,076.3	127.298	0.1	(482,198.2)
2048	-	-	-	3,194.2	36,733.2	-	990.2	990.2	109.987	0.1	(482,088.3)
2049	-	-	-	2,938.7	33,794.5	-	911.0	911.0	95.030	0.1	(481,993.2)
2050	-	-	-	2,703.6	31,091.0	-	838.1	838.1	82.107	0.1	(481,911.1)
2051	-	-	-	2,487.3	28,603.7	-	771.1	771.1	70.942	0.1	(481,840.2)
2052	-	-	-	2,288.3	26,315.4	-	709.4	709.4	61.294	0.1	(481,778.9)
2053	-	-	-	2,105.2	24,210.2	-	652.6	652.6	52.959	0.1	(481,725.9)
Total	-	-	(599,500.0)	575,289.8		(599,500.0)	178,339.8	(421,160.2)	(481,725.9)		

Alternative 3- 50V-Klondike 4kV Conversions, 36V-Hillaton Load Transfers

Table 9 Alternative 3- 50V-Klondike 4kV Conversions, 36V-Hillaton Load Transfers

99V-Highbury Road

Reconfiguration of 36V-Hilaton with Load transfer to 50V-Klondoke

Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2013	-	-	(195,000.0)	-	-	(195,000.0)	-	(195,000.0)	(195,000.000)	1.0	(195,000.0)
2014	-	-	(559,000.0)	-	-	(559,000.0)	-	(559,000.0)	(524,981.217)	0.9	(719,981.2)
2015	-	-	(842,000.0)	63,840.0	1,596,000.0	(842,000.0)	19,790.4	(822,209.6)	(725,181.069)	0.9	(1,445,162.3)
2016	-	-	(100,000.0)	130,572.8	1,501,587.2	(100,000.0)	40,477.6	(59,522.4)	(49,303.363)	0.8	(1,494,465.6)
2017	-	-	-	120,127.0	1,381,460.2	-	37,239.4	37,239.4	28,968.771	0.8	(1,465,496.9)
2018	-	-	-	110,516.8	1,270,943.4	-	34,260.2	34,260.2	25,029.366	0.7	(1,440,467.5)
2019	-	-	-	101,675.5	1,169,267.9	-	31,519.4	31,519.4	21,625.673	0.7	(1,418,841.8)
2020	-	-	-	93,541.4	1,075,726.5	-	28,997.8	28,997.8	18,684.842	0.6	(1,400,157.0)
2021	-	-	-	86,058.1	989,668.4	-	26,678.0	26,678.0	16,143.928	0.6	(1,384,013.1)
2022	-	-	-	79,173.5	910,494.9	-	24,543.8	24,543.8	13,948.548	0.6	(1,370,064.5)
2023	-	-	-	72,839.6	837,655.3	-	22,580.3	22,580.3	12,051.713	0.5	(1,358,012.8)
2024	-	-	-	67,012.4	770,642.9	-	20,773.9	20,773.9	10,412.825	0.5	(1,347,600.0)
2025	-	-	-	61,651.4	708,991.5	-	19,111.9	19,111.9	8,996.806	0.5	(1,338,603.2)
2026	-	-	-	56,719.3	652,272.1	-	17,583.0	17,583.0	7,773.348	0.4	(1,330,829.8)
2027	-	-	-	52,181.8	600,090.4	-	16,176.3	16,176.3	6,716.266	0.4	(1,324,113.6)
2028	-	-	-	48,007.2	552,083.1	-	14,882.2	14,882.2	5,802.935	0.4	(1,318,310.6)
2029	-	-	-	44,166.7	507,916.5	-	13,691.7	13,691.7	5,013.806	0.4	(1,313,296.8)
2030	-	-	-	40,633.3	467,283.2	-	12,596.3	12,596.3	4,331.988	0.3	(1,308,964.8)
2031	-	-	-	37,382.7	429,900.5	-	11,588.6	11,588.6	3,742.890	0.3	(1,305,221.9)
2032	-	-	-	34,392.0	395,508.5	-	10,661.5	10,661.5	3,233.902	0.3	(1,301,988.0)
2033	-	-	-	31,640.7	363,867.8	-	9,808.6	9,808.6	2,794.130	0.3	(1,299,193.9)
2034	-	-	-	29,109.4	334,758.4	-	9,023.9	9,023.9	2,414.162	0.3	(1,296,779.7)
2035	-	-	-	26,780.7	307,977.7	-	8,302.0	8,302.0	2,085.865	0.3	(1,294,693.9)
2036	-	-	-	24,638.2	283,339.5	-	7,637.8	7,637.8	1,802.212	0.2	(1,292,891.7)
2037	-	-	-	22,667.2	260,672.3	-	7,026.8	7,026.8	1,557.133	0.2	(1,291,334.5)
2038	-	-	-	20,853.8	239,818.5	-	6,464.7	6,464.7	1,345.382	0.2	(1,289,989.2)
2039	-	-	-	19,185.5	220,633.1	-	5,947.5	5,947.5	1,162.426	0.2	(1,288,826.7)
2040	-	-	-	17,650.6	202,982.4	-	5,471.7	5,471.7	1,004.350	0.2	(1,287,822.4)
2041	-	-	-	16,238.6	186,743.8	-	5,034.0	5,034.0	867.771	0.2	(1,286,954.6)
2042	-	-	-	14,939.5	171,804.3	-	4,631.2	4,631.2	749.764	0.2	(1,286,204.8)
2043	-	-	-	13,744.3	158,060.0	-	4,260.7	4,260.7	647.805	0.2	(1,285,557.0)
2044	-	-	-	12,644.8	145,415.2	-	3,919.9	3,919.9	559.712	0.1	(1,284,997.3)
2045	-	-	-	11,633.2	133,782.0	-	3,606.3	3,606.3	483.597	0.1	(1,284,513.7)
2046	-	-	-	10,702.6	123,079.4	-	3,317.8	3,317.8	417.834	0.1	(1,284,095.9)
2047	-	-	-	9,846.4	113,233.0	-	3,052.4	3,052.4	361.014	0.1	(1,283,734.9)
2048	-	-	-	9,058.6	104,174.4	-	2,808.2	2,808.2	311.920	0.1	(1,283,423.0)
2049	-	-	-	8,334.0	95,840.5	-	2,583.5	2,583.5	269.503	0.1	(1,283,153.5)
2050	-	-	-	7,667.2	88,173.2	-	2,376.8	2,376.8	232.854	0.1	(1,282,920.6)
2051	-	-	-	7,053.9	81,119.4	-	2,186.7	2,186.7	201.188	0.1	(1,282,719.4)
2052	-	-	-	6,489.5	74,629.8	-	2,011.8	2,011.8	173.829	0.1	(1,282,545.6)
2053	-	-	-	5,970.4	68,659.4	-	1,850.8	1,850.8	150.190	0.1	(1,282,395.4)
Total	-	-	##########	1,627,340.6		###########	504,475.6	(1,191,524.4)	(1,282,395.4)		

Summary

Month	Number of Stations Peaking	Percent
January	41	31%
February	43	33%
March	9	7%
April	4	3%
May	2	2%
June	0	0%
July	3	2%
August	4	3%
September	6	5%
October	0	0%
November	3	2%
December	13	10%
Not Known	4	3%

* Generator Transformers are not included
* Dedicated customer transformers are not included.
* NK = Not Known

(a) Station Name	(e) Peak Load	Unit	(f) Peak Occurrence:
Substation 1	8.2	MVA	Jan-13
Substation 2	5.9	MVA	24-Jan-13 19:44
Substation 3	7.2	MVA	Jan-13
Substation 4	8.3	MVA	Jan-13
Substation 5	5.6	MVA	Jan-13
Substation 6	40.8	MW	02-Jan-13 17:30
Substation 7	40.7	MW	23-Jan-13 18:14
Substation 8	14.8	MVA	02-Jan-13 18:00
Substation 9	19.2	MVA	23-Jan-13 17:34
Substation 10	14.4	MVA	23-Jan-13 17:31
Substation 11	17.3	MVA	Jan-13
Substation 12	27.3	MVA	06-Jan-13 16:30
Substation 13	69.9	MVA	23-Jan-13 18:00
Substation 14	288.7	MW	23-Jan-13 12:16
Substation 15	78.4	MVA	23-Jan-13 18:15
Substation 16	29.2	MVA	02-Jan-13 17:45
Substation 17	33.0	MW	24-Jan-13 08:00
Substation 18	108.3	MVA	24-Jan-13 18:30
Substation 19	7.0	MVA	Jan-13
Substation 20	49.3	MVA	23-Jan-13 17:30
Substation 21	6.6	MVA	Jan-13
Substation 22	129.8	MVA	24-Jan-13 19:00
Substation 23	11.8	MVA	Jan-13

(a) Station Name	(e) Peak Load	Unit	(f) Peak Occurrence:
Substation 24	6.4	MVA	Jan-13
Substation 25	35.3	MVA	Jan-13
Substation 26	10.1	MVA	Jan-13
Substation 27	5.1		28-Jan-13 18:00
Substation 28	6.6	MVA	Jan-13
Substation 29	6.1	MVA	Jan-13
Substation 30	7.9	MVA	Jan-13
Substation 31	8.4	MVA	Jan-13
Substation 32	2.5	MVA	Jan-13
Substation 33	21.0	MVA	Jan-13
Substation 34	3.2	MVA	Jan-13
Substation 35	18.5	MW	24-Jan-13 17:38
Substation 36	91.9	MW	06-Jan-13 04:58
Substation 37	166.9	MVA	24-Jan-13 17:30
Substation 38	343.0	MW	12-Jan-12 07:00
Substation 39	25.0	MVA	Jan-2013
Substation 40	147.9	MVA	02-Jan-13 13:45
Substation 41	3.6		31-Jan-13 22:08
Substation 42	62.3	MVA	17-Feb-13 18:25
Substation 43	1.4	MVA	Feb-13
Substation 44	5.3	MVA	Feb-13
Substation 45	20.0	MW	07-Feb-13 21:42
Substation 46	74.2	MVA	28-Feb-13 10:00
Substation 47	20.2	MVA	Feb-13
Substation 48	16.9	MVA	08-Feb-13 07:30
Substation 49	5.8	MVA	Feb-13
Substation 50	7.5	MVA	Feb-13
Substation 51	104.4	MVA	08-Feb-13 18:00
Substation 52	24.4	MW	08-Feb-13 09:14
Substation 53	9.2	MVA	Feb-13
Substation 54	18.1	MVA	Feb-13
Substation 55	25.0	MVA	08-Feb-13 07:00
Substation 56	60.9	MW	08-Feb-13 07:00
Substation 57	32.8	MW	04-Feb-13 17:36
Substation 58	9.4	MVA	Feb-13
Substation 59	5.7	MVA	Feb-13
Substation 60	3.1	MVA	Feb-13
Substation 61	28.0	MVA	Feb-13
Substation 62	4.7	MVA	Feb-13
Substation 63	45.4	MVA	01-Feb-13 00:00
Substation 64	9.1	MVA	Feb-13
Substation 65	7.5	MVA	Feb-13
Substation 66	3.3	MVA	Feb-13
Substation 67	9.9	MVA	Feb-13

(a) Station Name	(e) Peak Load	Unit	(f) Peak Occurrence:
Substation 68	10.1	MVA	Feb-13
Substation 69	3.2	MVA	Feb-13
Substation 70	3.6	MVA	Feb-13
Substation 71	3.0	MVA	Feb-13
Substation 72	4.1	MVA	Feb-13
Substation 73	2.6	MVA	Feb-13
Substation 74	31.0	MVA	Feb-13
Substation 75	3.3	MVA	Feb-13
Substation 76	8.9	MVA	Feb-13
Substation 77	0.9	MVA	Feb-2013
Substation 78	14.9	MVA	Feb-13
Substation 79	27.9	MVA	Feb-13
Substation 80	50.3	MVA	08-Feb-13 07:15
Substation 81	500.3	MVA	21-Feb-13 11:15
Substation 82	238.2	MVA	07-Feb-13 16:45
Substation 83	83.5	MVA	08-Feb-13 11:00
Substation 84	68.3	MVA	08-Feb-13 10:45
Substation 85	183.3	MVA	26-Mar-13 08:30
Substation 86	8.8	MW	Mar-13
Substation 87	10.9	MVA	Mar-13
Substation 88	10.6	MVA	Mar-13
Substation 89	31.8	MVA	Mar-13
Substation 90	3.1	MVA	Mar-13
Substation 91	7.4	MVA	Mar-13
Substation 92	5.7	MVA	Mar-13
Substation 93	183.3	MVA	26-Mar-13 08:30
Substation 94	7.4	MVA	Apr-13
Substation 95	18.0	MVA	Apr-2013
Substation 96	48.5	MW	16-Apr-13 20:30
Substation 97	31.9	MVA	05-Apr-13 13:45
Substation 98	16.7	MVA	May-13
Substation 99	10.8	MVA	May-13
Substation 100	11.1	MVA	16-Jul-12 13:00
Substation 101	3.3	MVA	Jul-13
Substation 102	111.8	MVA	15-Jul-12 08:30
Substation 103	35.7	MVA	14-Aug-12 13:48
Substation 104	29.9	MVA	Aug-12
Substation 105	25.7	MW	20-Aug-12 16:54
Substation 106	0.7	MVA	Aug-12
Substation 107	7.6	MVA	Sep-2013
Substation 108	13.9	MVA	Sep-2012
Substation 109	4.3	MVA	Sep-12
Substation 110	7.8	MW	11-Sep-12 02:12
Substation 111	14.5	MVA	12-Sep-12 10:30

(a) Station Name	(e) Peak Load	Unit	(f) Peak Occurrence:
Substation 112	8.8	MVA	Sep-12
Substation 113	62.8	MW	19-Nov-12 17:25
Substation 114	13.7	MVA	Nov-12
Substation 115	67.5	MVA	27-Nov-12 19:30
Substation 116	2.8	MVA	Dec-12
Substation 117	12.4	MVA	Dec-12
Substation 118	27.4	MVA	Dec-12
Substation 119	17.2	MVA	Dec-12
Substation 120	15.3	MVA	Dec-12
Substation 121	12.2	MVA	Dec-12
Substation 122	7.9	MVA	Dec-12
Substation 123	9.7	MVA	Dec-12
Substation 124	6.8	MVA	Dec-12
Substation 125	9.8	MVA	Dec-12
Substation 126	503.3	MVA	18-Dec-12 16:00
Substation 127	27.5	MVA	21-Dec-11 06:45
Substation 128	22.3	MW	31-Dec-12 02:56
Substation 129	NK		NK
Substation 130	NK		NK
Substation 131	NK		NK
Substation 132	7.9		NK

5279.2

Renewable to Retail (NSUARB M06214)
NSPI Responses to Consumer Advocate Data Requests

NON-CONFIDENTIAL

Request DR-5:

Please provide any information that NS Power believes is relevant to the time periods in which residential load is most likely to contribute to peak loads on

(a) shared line transformers,

(b) feeders, and

(c) distribution substations.

Response DR-5:

(a-c) NS Power has not conducted studies concerned with time periods in which residential load contributes to peak loads on its individual transformers, feeders and distribution substations. For the allocation purposes of demand-related costs of distribution in its Cost of Service Studies, the Company uses class non-coincident annual demands as presented in Exhibit 9B included in Appendix C. Please refer to **Attachment 1** which was CA DR-4 from the 2013 COS proceeding[1] for information on dates and hours of class annual peaks. Note that some rate classes peak during non-winter months and outside of on-peak daily periods.

[1] 2013 NS Power Cost of Service Study, M05473, Exhibit N-1, Appendix B, June 28, 2013.

Request DR-4:

Date and time of each monthly class NCP in COSS Sheet "Input Data Two"

Response DR-4:

The class non-coincident peak is selected from the constructed forecast load shape file as the maximum hourly load in each specific rate class for each month.

Rate Class	Date	Time	Peak MW
Domestic	Tue, Feb-02	19:00	1,037
Small General	Thu, Feb-04	12:00	56
General Demand	Mon, Jan-11	10:00	488
Large General	Thu, Sep-02	11:00	73
Small Industrial	Tue, Aug-31	12:00	48
Medium Industrial	Fri, Dec-10	09:00	85
Large Industrial	Fri, Sep-03	15:00	139
ELI 2P-RTP			0
Municipal	Wed, Feb-03	09:00	41
Unmetered	Thu, Dec-02	00:00	24
Bowater Mersey	N/A (calculated)		42
Gen. Repl. & Load Follow.	Tue, Sep-21	00:00	24
RTP			0
LRT	N/A (calculated)		38

Renewable to Retail (NSUARB M06214)
NSPI Responses to Consumer Advocate Data Requests

NON-CONFIDENTIAL

Request DR-6:

If the probability of customer load contributing to distribution peak loads varies over time, please explain whether NS Power favours time-differentiating the DT rate for customers on the Time of Use rate.

(a) If NS Power believes that the probability of customer load contributing to distribution peak loads does not vary over time, please explain why.

(b) If NS Power believes that the probability of customer load contributing to distribution peak loads varies over time, but does not believe that the Time of Use DT rate should be time-differentiated, please explain why.

Response DR-6:

(a-b) As provided in section 9.0 of the Distribution Tariff Strawman of May 21, 2015, in its design of the Distribution Tariff, NS Power was guided, among other criteria, by the objective of leveraging existing rates and processes. The existing rate setting methodology does not provide cost information or guidelines on the basis of which a Time-Of-Day (TOD) differentiated distribution tariff could be developed for residential customers.

The current residential TOD rates have been designed for bundled service customers utilizing Electric Thermal Storage (ETS) load shifting equipment without consideration of savings arising specifically from changes in utilization of distribution infrastructure. The primary motivation for the development of the TOD Tariff was the deferral of investment in generation assets. Consistent with this, the highest TOD rates apply during morning and evening periods in January, February and December. While the system total load always peaks during these periods, the load on individual distribution substations and feeders may not. This approach is also reflected in the design of the 1P-RTP adders

NON-CONFIDENTIAL

whose generation cost component is differentiated by the time of day, while the transmission and distribution costs are not.

Cost of Service Studies are conducted for the TOD and non-TOD residential rate classes combined and therefore TOD class-specific cost information is not available from the COS. Further, the COS apportions all distribution costs to rate classes on the basis of annual usage (total number of customers or annual peak) without consideration of time of day or season-differentiated periods.

Please refer also to CA DR-5. The Company has not conducted studies concerned with time periods in which residential load contributes to peak loads on its distribution assets and therefore does not know whether the probability of customer load contributing to distribution peak loads varies over time. As such, the Company does not have information as to what time of day and seasonal periods the DT rates should be differentiated and by what amounts.

NON-CONFIDENTIAL

Request DR-1:

Reference: LRS Terms and Conditions

Re definition of "Energy Balancing Services Tariff", should the last phrase "from the LRS through qualifying generators" be changed to "from qualifying generators through the LRS"?

Response DR-1:

NS Power agrees with the change suggested and the definition of "Energy Balancing Services Tariff" in the LRS Terms and Conditions has been modified as follows:

Energy Balancing Services Tariff: A NS Power tariff, approved by the Board, which provides supplementary generation service to Licensed Retail Suppliers for the delivery of energy to RtR Customers and reception by NS Power of surplus generation from qualifying generators through the LRS.

NON-CONFIDENTIAL

Request DR-2:

Reference: LRS Terms and Conditions

The definition of "Tariffed Services" excludes the DT, which is confusing since the service provided under the DT has an associated tariff. The difference appears to be that some services are supplied by NSPI to the LRS and the distribution service is provided directly to the RtR customer. Would it be appropriate to change "Tariffed Services" to something like "Tariffed Services Provided to the LRS"?

Response DR-2:

NS Power agrees that the clarification suggested is beneficial in distinguishing that certain tariffs are applicable to the LRS while the Distribution tariff is applicable directly to the RtR customer. Subject to any further revisions required through the process, the term "Tariffed Services" will be modified to "LRS Tariffed Services" in the LRS Terms and Conditions and LRS Participation Agreement documents.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-3:

Reference: LRS Terms and Conditions

Re Section 8(e), why "in a form acceptable to NS Power" as opposed to "in accordance with Board regulations"?

Response DR-3:

The requirement in Section 8(e) states that "The LRS is responsible for obtaining and providing the RtR Customer's written consent, in a form acceptable to NS Power, in support of any transaction requests made to NS Power on behalf of the RtR Customer."

This requirement is necessary in the LRS Terms and Conditions as NS Power is obligated to obtain a customer's explicit consent before carrying out transactions requested by an LRS on behalf of the customer. In the draft version of the Board's Electricity Retailers Regulations (as issued May 12, 2015), Section 28 stipulates that the Licence Holder will not submit a request to the Distributor to transfer a Customer to the Licence Holder's supply unless that Customer has agreed to a contract with the Licence Holder.

NS Power recommends that Licence Holders provide the Customer's written consent in support of any transaction request, as described in the Draft LRS Terms and Conditions Section 8, and NS Power's June 10, 2015 Comments on the draft Board Electricity Retailers Regulations. If the Board adopts this as the form of consent, NS Power will accept it. If the Board rejects or amends this recommendation, NS Power will consider alternatives.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-4:

Reference: LRS Terms and Conditions

Section 8(g) requires the provision of up to date customer information. As written, information that is up to date at the time of submission to NS Power would satisfy the requirement. Is there a responsibility to keep this current?

Response DR-4:

Yes, the intent of Section 8(g) is that the LRS would maintain the responsibility to provide NS Power with up-to-date customer information throughout the term of its contract with the RtR customer.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-5:

Reference: LRS Terms and Conditions

Re 8(h), is the LRS the point of contact for all customers in all cases? For example, in the event of an outage, does the customer call the LRS or NS Power?

Response DR-5:

NS Power believes that the LRS would be the appropriate point of contact for most RtR customer retail and commercial matters. NS Power agrees that it should be the point of contact for matters related to its connection with the NS Power system such as outages, line extension requests, tree trimming, etc.

Subject to any further revisions that may be required, NS Power will revise the LRS Terms and Conditions and the Distribution Tariff as follows:

- Added to Section 7 of the Distribution Tariff (NS Power Responsibilities):

  (d) acting as the point of contact for RtR Customers for matters related to receipt of Distribution Access Service.

- Added to Section 8 of the LRS Terms and Conditions (NS Power Responsibilities):

  (g) acting as the point of contact for RtR Customers for matters related to receipt of Distribution Access Service.

NON-CONFIDENTIAL

Request DR-6:

Reference: LRS Terms and Conditions

Re 9(e), are there any customer sites not subject to Load Settlement?

Response DR-6:

The intent of Clause 9(e) is to define for which customer sites information is necessary for NS Power to maintain in order to conduct load settlement. Subject to any further revisions required through this process, the clause will be revised to provide this clarification, as follows:

9(e) maintaining Customer Information for all customer sites as necessary to perform Load Settlement;

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-7:

Reference: LRS Terms and Conditions

Section 9.1 states that an interruption in tariffed services does not relieve the customer of any charges "pursuant to any NS Power tariffs applicable to Tariffed Services during the period of such suspension". If the Tariffed Service is suspended, how can any charges arise during the suspension period?

Response DR-7:

This provision addresses charges that are not usage based, such as a tariff's monthly administration fee (as proposed in the Energy Balancing Services Tariff), contract demand amount (as proposed in the Standby Services Tariff) or charges for certain Ancillary Services under the OATT, which would still apply notwithstanding the occurrence of an interruption in the delivery of the service.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-8:

Reference: LRS Terms and Conditions

The last paragraph on page 10 addresses NS Power's right to refuse the return of a customer. Presumably, the intention here is to treat these customers in the same manner as if they had not left NSPI's system; i.e. the normal connection and disconnection Regulations apply? If so, should this paragraph reference the relevant Regulations? Also, how does NS Power refuse to accept an RtR customer? (E.g., if the LRS informs NS Power that as of a certain date, customer A is no longer one of its customers, does NS Power disconnect the customer on that date?)

Response DR-8:

It is NS Power's intention to apply the NS Power Regulations related to establishment of service for customers returning to NS Power bundled service supply. This will address the requirements provision of a deposit, etc.

Section 10 of LRS T&C says:

> NS Power reserves the right to refuse to accept an RtR Customer Transaction Request Application for any Retail Customer who has outstanding debt payable to NS Power in relation to previous electric service at the Retail Customer Premises identified in the RtR Customer Transaction Request Application.

Customers returning to NS Power supply from an LRS will generally not have outstanding debt to NS Power as they will have settled it upon departure. However, to allow for this possibility, subject to any further revisions that arise during this process, NS Power intends to add the following paragraph to the end of Section 16, on page 18.

> In the event of an RtR Customer reverting to NS Power's Bundled Service, NS Power reserves the right to refuse to accept an RtR Customer Transaction Request Application for any Retail Customer who has outstanding debt payable to NS Power in relation to previous electric service at the Retail Customer Premises identified in the RtR Customer Transaction Request Application. NS Power Regulations including, but not limited to application for service, connection and disconnection of service, payment of accounts and deposits apply to the RtR Customer's return to NS Power Bundled Service.

The process for transfer back to NS Power supply from RtR supply starts with the LRS initiating an RtR Customer Transaction Request Application requesting the transfer. NS Power then reviews the request and notifies the LRS if it has been accepted or rejected. In the case of a customer with arrears from previous electric service with NS Power asking to return to NS Power bundled service supply, NS Power would not accept the transfer request until payment arrangements have been agreed to with the customer, in accordance with NS Power Regulations. If suitable payment arrangements have not been agreed to by the customer, then the process for service disconnection for non-payment would proceed in accordance with NS Power Regulations 6.1, 6.2 and 6.3. The LRS would continue to be responsible for the provision of service to the RtR customer until the payment arrangements were in place and accepted by NS Power, or the disconnection was completed by NS Power. If payment arrangements were made, NS Power would notify the LRS that the transfer to NS Power supply would be effective upon receipt of the meter reading. Otherwise, if payment arrangements have not been made, NS Power Regulations with respect to a disconnect apply, and NS Power would notify the LRS upon completion of the service disconnection.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-9:

Reference: LRS Terms and Conditions

(a) Re top of page 11, is there a timeframe for NS Power acceptance or rejection?

(b) Can transfers take place other than at normal meter reading dates?

Response DR-9:

(a) No timeframe was provided in the LRS Terms and Conditions. However, NS Power anticipates that this would be determined during development of NS Power's supporting administrative and business processes.

(b) Yes:

(i) With the proposed implementation of remotely poll-able interval meters, NS Power anticipates that special meter readings will be able to be obtained, off the normal meter reading scheduled dates; and

(ii) Transfers to an LRS of customers who do not have an interval meter will depend on the scheduling of necessary meter installations. Unless the transfer is requested to be deferred beyond that metering installation date, the transfer would normally take place on the completion of the metering installation.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-10:

Reference: LRS Terms and Conditions

Re the reference to separate fees associated with interval metering in Section 12.1, does this mean that such fees are separately identified on the bill, and is the bill to the LRS or the customer?

Response DR-10:

The method for billing fees associated with provision of remotely poll-able metering has not been finalized. However, it is anticipated that a separate fee will be charged for metering devices and that an ongoing fee will be applicable for services related to communications to the meters. These charges will be billed to the LRS, as the interval metering is necessary for aggregation of the LRS's customer load, and not necessary for determination of Distribution Tariff charges which otherwise could be billed on a standard cumulative meter.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-11:

Reference: LRS Terms and Conditions

Re potentially estimated meter readings in Section 12.2, does this include estimating whatever is necessary with respect to tariffed services? How would that be done?

Response DR-11:

In the event that an unexpected technical issue with the meter or other equipment caused some data to be lost, estimation could be required. The estimation methodology used could vary depending on the extent and duration of the data loss. For data losses over short timeframes (several hours), interpolation of values could be used. For longer durations (days), class load shapes could be used to develop estimated hourly values for the missing periods. In addition, historical customer load shapes would be used to estimate the profile of the missing data.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-12:

Reference: LRS Terms and Conditions

Section 13.2 suggests that any ECR will be collected under OATT. Is this the intention?

Response DR-12:

With respect to Embedded Cost Recovery (ECR), NS Power's intention is to collect stranded embedded costs under a separate tariff outside of OATT. The Company will propose appropriate wording changes to Section 13.2 of the LRS Terms and Conditions concurrent with the submission of the draft of the ECR tariff.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-13:

Reference: LRS Terms and Conditions

Re the twenty days in Section 13.5, is this consistent with the time frame other NSPI customers have to pay? Does it need to be? If the LRS has to pay in 20 days, does the LRS need to collect from its customers in 20 days? Is this less time than the customer currently has to pay?

Response DR-13:

The twenty day payment period is consistent with the timeframe in the OATT (Section 7.1); this aligns the payment of the LRS's aggregated charges (which includes payment for services under the OATT) to this timeframe.

For NS Power's bundled service customers, bills are due on the billing date. If a bill remains unpaid for a period of thirty days after the billing date, the service is subject to disconnection for non-payment (NS Power Regulations 5.4, 5.3). Bills issued on a bi-monthly basis and which are not paid within thirty (30) days after the billing date are subject to an interest charge. Bills issued on a monthly basis, including the Residential Budget Plan, and which are not paid within twenty (20) days after the billing date are subject to an interest charge. Group bills are also due on the billing date, however those not paid within seventeen (17) days are subject to an interest charge.

It is not a requirement in the LRS Terms and Conditions that the LRS collect from its customers within a twenty day period.

NON-CONFIDENTIAL

Request DR-14:

Reference: LRS Terms and Conditions

Re Section 14, how does NS Power "suspend tariffed services"? As per Section 15, such suspension appears to mean that NS Power takes over the customer and the security deposit of the LRS comes into play. Is this a correct interpretation?

Response DR-14:

Suspension of tariffed services is intended to be temporary and is achieved through withdrawal of the tariffed services (i.e. transmission service, ancillary services, energy balancing and standby services) provided to the LRS, by the NSPSO. In this case, the LRS would not have the necessary services to enable transport of electricity from the RtR generators to the RtR customers.

The interpretation in the question is correct. Under such a suspension, the LRS's customers would continue to receive electricity from the NS Power system by virtue of their connection to the NS Power system. In the case of suspension of tariffed services to an LRS, that LRS's customers will be deemed to have been transferred to NS Power's bundled service (or to another LRS in the case of a pending valid transfer request made prior to the suspension). The security provided by the LRS to NS Power becomes due and payable to NS Power in the event of LRS default.

The transfer of a customer back to the LRS could occur once the amount owing has been paid by the LRS, or from the LRS's security and new security has been established.

The language in section 14 regarding default and suspension of services is consistent with Section 7.3 of the OATT and aligns with the FERC pro-forma tariff.

NON-CONFIDENTIAL

Request DR-15:

Reference: LRS Terms and Conditions

These Terms and Conditions appear to assume a model of the LDS purchasing from a generator and delivering to customers using NSPI's T & D system. Would they need to change to accommodate a different model such as one where the generation and load are both behind the customer meter? If load and generation are both behind the meter, does it qualify as RtR?

Response DR-15:

The proposed LRS Terms and Conditions, tariffs and other draft documents issued to date were designed assuming a renewable low-impact generator would be connected using NS Power's Transmission and Distribution System. If the Act permits a market model where the generation and load are both behind the customer meter to be considered a Renewable to Retail service, NS Power would reassess the design of the tariffs, LRS participation requirements, Market Rules and Procedures to address this development, within the requirements of the Act.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-16:

Reference: Distribution Tariff Draft and Attachments

Re page 10, Lines 6-9, please elaborate on how retail capital and operating costs are functionalized.

Response DR-16:

Under the approved Cost of Service Studies, capital investment is functionalized among the three functional areas of generation, transmission and distribution. Please refer to **Attachment 1,** page 3. Attachment 1 is a print version of Tab 2B of Attachment C, the Excel Cost of Service Model that was issued to stakeholders with the Draft Distribution Tariff on May 21, 2015.

Direct operating expenses are functionalized into the retail area based on the Uniform System of Accounts, mandated by the National Association of Regulatory Utility Commissioners (NARUC), followed by NS Power in its accounting practice. In addition to this, some miscellaneous revenues and a portion of the overhead expenses of the Company are also functionalized to retail.[1] The retail-related overhead expenses are apportioned to the individual direct retail expense categories based on their relative shares in the total direct retail expenses. Please refer to **Attachment 2,** page 4. Attachment 2 is a print version of Tab 5 in Attachment C of May 21, 2015. It contains a list of operating costs and miscellaneous revenues functionalized to retail, as well as proration formulas used in assignment of overhead retail costs to individual direct retail cost categories.

[1] Note that a final report on the COS treatment of Miscellaneous Revenues and Overhead Cost, includes recommendations regarding changes to the current approach. M06555, Exhibit N-2, February 9, 2015.

NOVA SCOTIA POWER INC.
CLASSIFICATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
		DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1)	**GENERATION FUNCTION**									
(2)										
(3)	STEAM PLANT	$1,191,036	$179,496	$0	($673,293)	$673,293	$0	$517,743	$852,789	$0
(4)	HYDRO PLANT	366,637	4,824	0	-207,260	207,260	0	159,377	212,084	0
(5)	WIND PLANT	201,182	0	0	-179,039	179,039	0	22,143	179,039	0
(6)	LM6000 PLANT	71,417	0	0	-40,372	40,372	0	31,045	40,372	0
(7)	GAS TURBINE PLANT - OTHER	6,513	0	0	0	0	0	6,513	0	0
(8)	TOTAL GENERATION PLANT	1,836,785	184,320	0	-1,099,963	1,099,963	0	736,822	1,284,283	0
(9)										
(10)	GENERAL PROPERTY PLANT	137,057	13,754	0	-82,077	82,077	0	54,980	95,830	0
(11)	TOTAL PLANT IN SERVICE	1,973,842	198,074	0	-1,182,040	1,182,040	0	791,802	1,380,114	0
(12)	Working Capital & Deferred									
(13)	Charges/Credits:									
(14)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(15)	CASH - OTHER	4,223	9,353	0	0	0	0	4,223	9,353	0
(16)	MAT. & SUPPLIES - FUEL	0	84,441	0	0	0	0	0	84,441	0
(17)	MAT. & SUPPLIES - OTHER	16,768	1,683	0	-10,041	10,041	0	6,726	11,724	0
(18)	DEF. CHG. - Financing	38,421	3,856	0	-23,009	23,009	0	15,413	26,864	0
(19)	DEF. CHG. - Tax	6,665	669	0	-3,991	3,991	0	2,674	4,660	0
(20)	DEF. CHG. - Pension	12,601	27,906	0	0	0	0	12,601	27,906	0
(21)	DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0
(22)	DEF. CHG. - Fuel Deferral	0	-5,043	0	0	0	0	0	-5,043	0
(23)	DEF. CHG. - Other	1,637	164	0	-980	980	0	657	1,144	0
(24)	DEF. CHG. - FCR	17,170	1,723	0	-10,282	10,282	0	6,888	12,005	0
(25)	DEF. CR. - ARO Steam	-37,934	-5,717	0	21,444	-21,444	0	-16,490	-27,161	0
(26)	DEF. CR. - ARO Hydro	-22,466	-296	0	12,700	-12,700	0	-9,766	-12,996	0
(27)	DEF. CR. - ARO Wind	-10,720	-141	0	6,060	-6,060	0	-4,660	-6,201	0
(28)	DEF. CR. - ARO CT	-4,150	0	0	0	0	0	-4,150	0	0
(29)	DEF. CR. - Other	-5,716	-861	0	3,231	-3,231	0	-2,485	-4,092	0
(30)	CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0
(31)	SUB-TOTAL	16,498	117,737	0	-4,868	4,868	0	11,630	122,605	0
(32)								0	0	0
(33)	**TOTAL GENERATION FUNCTION**	1,990,340	315,810	0	-1,186,908	1,186,908	0	803,432	1,502,719	0
(34)										
(35)	**TRANSMISSION FUNCTION**									
(36)										
(37)	**Transmission - HV**	109,080	0	0	-61,663	61,663	0	47,417	61,663	0
(38)										
(39)	GENERAL PROPERTY PLANT	8,139	0	0	-4,601	4,601	0	3,538	4,601	0
(40)	TOTAL PLANT IN SERVICE	117,219	0	0	-66,264	66,264	0	50,955	66,264	0
(41)	Working Capital & Deferred									
(42)	Charges/Credits:									
(43)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(44)	CASH - OTHER	266	346	0	0	0	0	266	346	0
(45)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(46)	MAT. & SUPPLIES - OTHER	996	0	0	-563	563	0	433	563	0
(47)	DEF. CHG. - Financing	2,282	0	0	-1,290	1,290	0	992	1,290	0
(48)	DEF. CHG. - Tax	396	0	0	-224	224	0	172	224	0
(49)	DEF. CHG. - Pension	795	1,033	0	0	0	0	795	1,033	0
(50)	DEF. CHG. - Other	69	0	0	-39	39	0	30	39	0
(51)	DEF. CHG. - ARO Trans.	-5,787	0	0	3,271	-3,271	0	-2,516	-3,271	0
(52)	SUB-TOTAL	-984	1,380	0	1,156	-1,156	0	172	224	0
(53)										
(54)	Transmission - HV	116,235	1,380	0	-65,108	65,108	0	51,127	66,488	0

NOVA SCOTIA POWER INC.
CLASSIFICATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
		DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1)	**Transmission - EHV**	357,074	0	0	-201,854	201,854	0	155,220	201,854	0
(2)										
(3)	GENERAL PROPERTY PLANT	26,644	0	0	-15,062	15,062	0	11,582	15,062	0
(4)	TOTAL PLANT IN SERVICE	383,718	0	0	-216,916	216,916	0	166,802	216,916	0
(5)										
(6)	Working Capital & Deferred Charges/Credits:									
(7)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(8)	CASH - OTHER	872	1,134	0	0	0	0	872	1,134	0
(9)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(10)	MAT. & SUPPLIES - OTHER	3,260	0	0	-1,843	1,843	0	1,417	1,843	0
(11)	DEF. CHG. - Financing	7,469	0	0	-4,222	4,222	0	3,247	4,222	0
(12)	DEF. CHG. - Tax	1,296	0	0	-732	732	0	563	732	0
(13)	DEF. CHG. - Pension	2,601	3,382	0	0	0	0	2,601	3,382	0
(14)	DEF. CHG. - Other	225	0	0	-127	127	0	98	127	0
(15)	DEF. CHG. - FCR	4,357	0	0	-2,463	2,463	0	1,894	2,463	0
(16)	DEF. CR. - ARO Trans	-18,943	0	0	10,709	-10,709	0	-8,235	-10,709	0
(17)	SUB-TOTAL	1,136	4,516	0	1,321	-1,321	0	2,457	3,195	0
(18)										
(19)	Transmission - EHV	384,854	4,516	0	-215,595	215,595	0	169,259	220,111	0
(20)										
(21)	**TOTAL TRANSMISSION FUNCTION**	$501,090	$5,896	$0	($280,703)	$280,703	$0	$220,387	$286,599	$0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
		DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1)	**DISTRIBUTION FUNCTION**									
(2)										
(3)	DISTRIBUTION PLANT:									
(4)	LAND	$3,023	$0	$1,412	$0	$0	$0	$3,023	$0	$1,412
(5)	EASEMENTS & SURVEY	11,505	0	5,377	0	0	0	11,505	0	5,377
(6)	OTHER	1,493	0	697	0	0	0	1,493	0	697
(7)	SUBSTATIONS	30,113	0	0	0	0	0	30,113	0	0
(8)	POLES & FIXTURES	119,005	0	64,080	0	0	0	119,005	0	64,080
(9)	O.H. LINES	78,818	0	42,441	0	0	0	78,818	0	42,441
(10)	U.G. LINES	22,658	0	12,200	0	0	0	22,658	0	12,200
(11)	LINE TRANSFORMERS	163,242	0	0	0	0	0	163,242	0	0
(12)	SERVICES	0	0	60,998	0	0	0	0	0	60,998
(13)	METERS	0	0	25,072	0	0	0	0	0	25,072
(14)	STREET LIGHTING	10,251	0	0	0	0	0	10,251	0	0
(15)	TOTAL DISTRIBUTION PLANT	440,108	0	212,277	0	0	0	440,108	0	212,277
(16)										
(17)	GENERAL PROPERTY PLANT	32,840	0	15,840	0	0	0	32,840	0	15,840
(18)	TOTAL PLANT IN SERVICE	472,947	0	228,117	0	0	0	472,947	0	228,117
(19)										
(20)	Working Capital & Deferred Charges/Credits:									
(21)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(22)	CASH - OTHER	4,130	0	7,343	0	0	0	4,130	0	7,343
(23)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(24)	MAT. & SUPPLIES - OTHER	4,018	0	1,938	0	0	0	4,018	0	1,938
(25)	DEF. CHG. - Financing	9,206	0	4,440	0	0	0	9,206	0	4,440
(26)	DEF. CHG. - Tax	1,597	0	770	0	0	0	1,597	0	770
(27)	DEF. CHG. - Pension	12,321	0	21,908	0	0	0	12,321	0	21,908
(28)	DEF. CHG. - Other	277	0	134	0	0	0	277	0	134
(29)	SUB-TOTAL	31,548	0	36,533	0	0	0	31,548	0	36,533
(30)										
(31)	**(24) TOTAL DISTRIBUTION FUNCTION**	$504,496	$0	$264,650	$0	$0	$0	$504,496	$0	$264,650
(32)										
(33)	**RETAIL FUNCTION**									
(34)										
(35)	DISTRIBUTION PLANT:									
(36)	SERVICES	$0	$0	$0	$0	$0	$0	$0	$0	$0
(37)	METERS	0	0	0	0	0	0	0	0	0
(38)	TOTAL RETAIL PLANT	0	0	0	0	0	0	0	0	0
(39)										
(40)	GENERAL PROPERTY PLANT	0	0	0	0	0	0	0	0	0
(41)	TOTAL PLANT IN SERVICE	0	0	0	0	0	0	0	0	0
(42)										
(43)	Working Capital & Deferred Charges/Credits:									
(44)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(45)	CASH - OTHER	0	0	0	0	0	0	0	0	0
(46)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(47)	MAT. & SUPPLIES - OTHER	0	0	0	0	0	0	0	0	0
(48)	DEF. CHG. - Financing	0	0	0	0	0	0	0	0	0
(49)	DEF. CHG. - Tax	0	0	0	0	0	0	0	0	0
(50)	DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0
(51)	DEF. CHG. - Other	0	0	0	0	0	0	0	0	0
(52)	SUB-TOTAL	0	0	0	0	0	0	0	0	0
(53)										
(54)	**TOTAL RETAIL FUNCTION**	0	0	0	0	0	0	0	0	0
(55)										
(56)	**TOTAL AVE. RATE BASE**	**$2,995,925**	**$321,706**	**$264,650**	**($1,467,611)**	**$1,467,611**	**$0**	**$1,528,314**	**$1,789,317**	**$264,650**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	GENERATION FUNCTION				
(1)	FUEL	367,943	$0	$367,943	$0
(2)	PURCHASED PWR REG - IPP	896	390	507	0
(3)	PURCHASED PWR REG - BIOMASS	13,799	2,205	11,595	0
(4)	PURCHASED PWR WIND - FIXED	67,031	7,048	59,982	0
(5)	PURCHASED PWR REG - Imports	217	0	217	0
(6)	OPER. & MAINT. - STEAM	109,984	33,681	76,303	0
(7)	OPER. & MAINT. - HYDRO	12,650	3,874	8,776	0
(8)	OPER. & MAINT. - WIND	6,110	1,871	4,239	0
(9)	OPER. & MAINT. - BIOMASS	8,092	2,478	5,614	0
(10)	OPER. & MAINT. - LM6000	425	130	295	0
(11)	OPER. & MAINT. - OTHER CT's	1,257	1,056	201	0
(12)	DSM AMORTIZATION	1,056	385	671	0
(13)	FCR DEFERRAL	13,408	4,671	8,737	0
(14)	GRANTS IN LIEU OF TAXES	24,672	8,995	15,678	0
(15)	DEPRECIATION:				
(16)	STEAM	65,371	24,695	40,676	0
(17)	HYDRO	11,163	4,790	6,373	0
(18)	WIND	8,186	901	7,285	0
(19)	LM6000	2,084	906	1,178	0
(20)	GAS TURBINE - OTHER	1,202	1,202	0	0
(21)	GENERAL PROPERTY	25,696	9,368	16,328	0
(22)	INTEREST NET OF AFUDC	92,022	32,059	59,963	0
(23)	PREFERRED DIVIDENDS	5,106	1,779	3,327	0
(24)	CORPORATE TAXES	26,336	9,175	17,161	0
(25)	NON-OPERATING REVENUE:				
(26)	EXPORT SALES	-1,826	0	-1,826	0
(27)	OTHER REVENUE	-10,677	-1,873	-8,804	0
(28)	RETURN (PROFIT/LOSS)	77,701	27,070	50,631	0
(29)					
(30)	**TOTAL GENERATION**	**$929,904**	**$176,854**	**$753,049**	**$0**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	TRANSMISSION FUNCTION				
	Transmission - HV:				
(1)	O&M - HV	6,250	2,717	3,533	0
(2)	GRANTS IN LIEU OF TAXES	1,320	574	746	0
(3)	DEPRECIATION:				
(4)	TRANSMISSION	5,371	2,335	3,036	0
(5)	GENERAL PROPERTY	1,387	603	784	0
(6)	INTEREST NET OF AFUDC	4,693	2,040	2,653	0
(7)	PREFERRED DIVIDENDS	260	113	147	0
(8)	CORPORATE TAXES	1,343	584	759	0
(9)	NON-OPERATING REVENUE:				
(10)	OTHER REVENUE	-264	-115	-149	0
(11)	RETURN (PROFIT/LOSS)	3,963	1,723	2,240	0
	TOTAL - HV	**24,324**	**10,573**	**13,750**	**0**
	Transmission - EHV:				
(12)	O&M - HV	20,461	8,894	11,567	0
(13)	GRANTS IN LIEU OF TAXES	4,370	1,900	2,471	0
(14)	DEPRECIATION:				
(15)	TRANSMISSION	17,580	7,642	9,938	0
(16)	GENERAL PROPERTY	4,540	1,973	2,566	0
(17)	INTEREST NET OF AFUDC	15,537	6,754	8,783	0
(18)	PREFERRED DIVIDENDS	862	375	487	0
(19)	CORPORATE TAXES	4,447	1,933	2,514	0
(20)	NON-OPERATING REVENUE:				
(21)	OTHER REVENUE	-866	-376	-489	0
(22)	FCR DEFERRAL	3,092	1,344	1,748	0
(23)	RETURN (PROFIT/LOSS)	13,119	5,703	7,416	0
(24)	**TOTAL - EHV**	**83,143**	**36,142**	**47,001**	**0**
(25)	**TOTAL TRANSMISSION**	**$107,466**	**$46,716**	**$60,751**	**$0**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	DISTRIBUTION FUNCTION				
(1)	BEFORE STREETLIGHTS				
(2)	SUBSTATIONS	$306	$306	$0	$0
(3)	OVERHEAD LINES	38,749	25,187	0	13,562
(4)	UNDERGROUND LINES	693	451	0	243
(5)	LINE TRANSFORMERS	1,484	1,484	0	0
(6)	METERS	948	0	0	948
(7)	COMMUNICATIONS	8,880	8,880	0	0
(8)	GRANTS IN LIEU OF TAXES	7,858	5,117	0	2,740
(9)	DEPRECIATION:				
(10)	DISTRIBUTION - Land	0	0	0	0
(11)	DISTRIBUTION - Easements	433	295	0	138
(12)	DISTRIBUTION - Other	-3,612	-2,462	0	-1,150
(13)	DISTRIBUTION - Substations	906	906	0	0
(14)	DISTRIBUTION - Poles and Fixtures	18,878	12,271	0	6,607
(15)	DISTRIBUTION - OH Lines	7,800	5,070	0	2,730
(16)	DISTRIBUTION -UG Lines	1,669	1,085	0	584
(17)	DISTRIBUTION -Line Transformers	11,573	11,573	0	0
(18)	DISTRIBUTION -Services	6,646	0	0	6,646
(19)	DISTRIBUTION -Meters	3,721	0	0	3,721
(20)	GENERAL PROPERTY	8,294	5,595	0	2,699
(21)	INTEREST NET OF AFUDC	30,282	19,722	0	10,560
(22)	PREFERRED DIVIDENDS	1,680	1,094	0	586
(23)	CORPORATE TAXES	8,666	5,644	0	3,022
(24)	RETURN (PROFIT/LOSS)	25,569	16,653	0	8,917
	STREETLIGHTS				
	non-LED				
(25)	MAINTENACE	5,825	5,825	0	0
(26)	GRANTS IN LIEU OF TAXES	106	106	0	0
(27)	DEPRECIATION	1,924	1,924	0	0
(28)	INTEREST NET OF AFUDC	409	409	0	0
(29)	PREFERRED DIVIDENDS	23	23	0	0
(30)	CORPORATE TAXES	117	117	0	0
(31)	RETURN (PROFIT/LOSS)	345	345	0	0
(32)	Subtotal	8,750	8,750	0	0
(33)	OTHER REVENUE	-2,028	-1,366	0	-662
(35)	**TOTAL DISTRIBUTION**	**$188,147**	**$126,255**	**$0**	**$61,892**

EXHIBIT 5
Page 4 of 4

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	RETAIL FUNCTION				
(1)	QTY. ASSURANCE. & COMM.	5,401	0	0	5,401
(2)	CALL CENTRE	20,974	0	0	20,974
(3)	BILLING SERVICES	6,536	0	0	6,536
(4)	ELECT. WIRING INSPECT. - H/O	471	0	0	471
(5)	METER DATA SERVICES	831	0	0	831
(6)	METER READING - FIELD	10,853	0	0	10,853
(7)	ELECT. WIRING INSPECT. - FIELD	6,098	0	0	6,098
(8)	PAYMENT SERVICES	1,250	0	0	1,250
(9)	CREDIT SERVICES	0	0	0	0
(10)	BAD DEBT EXPENSE	5,704	0	0	5,704
(11)	MARKETING & SALES	2,047	0	0	2,047
(12)	COGS (NET OF RETAIL SALES)	-499	0	0	-499
(13)	GRANTS IN LIEU OF TAXES	0	0	0	0
(14)	DEPRECIATION:				
(15)	DISTRIBUTION	0	0	0	0
(16)	GENERAL PROPERTY	0	0	0	0
(17)	INTEREST NET OF AFUDC	0	0	0	0
(18)	PREFERRED DIVIDENDS	0	0	0	0
(19)	CORPORATE TAXES	0	0	0	0
(20)	NON-OPERATING REVENUE:				
(21)	LATE PAYMENT CHARGE	-5,330	0	0	-5,330
(22)	MISC. ELECTRIC	-1,969	0	0	-1,969
(23)	OTHER REVENUE	-737	0	0	-737
(24)	RETURN (PROFIT/LOSS)	0	0	0	0
(26)	**TOTAL RETAIL**	**$51,629**	**$0**	**$0**	**$51,629**
(27)	**TOTAL NET EXPENSES**	**$1,277,146**	**$349,825**	**$813,800**	**$113,521**

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-17:

Reference: Distribution Tariff Draft and Attachments

Re page 11, Lines 23-25, please provide details of how rate base and expenses are adjusted to remove the Municipals.

Response DR-17:

Please refer to the following table.

Category	Total	Transmission-connected customers	Municipal Class	Total Net of Municipal Class
Revenue Requirement (in thousands of $'s)				
Distribution	$188,147	NA	$801	$187,346
COS reference	Exh 5, Page 3 line 35, col 1		Exh 6,(Page 1, line 43, col 10 + Page 4, line 14, col 10)	
Retail	$51,629	$271	$176	$51,182
COS reference	Exh 5, Page 4, line 26, col 1	(Exh 6, (Page 4, line 38, col 8) * 5/32 + (Page 4, line 38 col 1) * 2/8	(Exh 6, Page 4, line 38 col 1) * 6/8	
Rate Base (In thousands of $'s)				
Distribution	$769,145	NA	$2,826	$766,319
COS reference	Exh 2A, Page 2, line 53, col 1		Exh 3,(Page 1, line 42, col 10 + Page 5, line 20, col 10)	

NON-CONFIDENTIAL

Please note that the value of the retail cost of retail customers set at $51,088 in the DT Strawman Report is incorrect due to an error in the original calculation. The correct value is $51,182. The Company will make an adjustment to the DT Tariff calculations to address this issue.

NON-CONFIDENTIAL

Request DR-18:

Reference: Distribution Tariff Draft and Attachments

Re page 12, Lines 1-3, does the COS distribution rate base and expenses already reflect that there are seven transmission connected customers? If not, what adjustments are necessary?

Response DR-18:

The COS distribution rate base and expenses already reflect that there are seven transmission-connected customers. No adjustments are necessary.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-19:

Reference: Distribution Tariff Draft and Attachments

Re page 12, Lines 14-15, please specify for each BTL what "applicable bundled ATL service" would apply.

Response DR-19:

The Large Industrial Distribution Tariff would apply to all distribution-connected large industrial customers billed under any Below-The-Line rates.

The Large General Distribution Tariff would apply to all distribution-connected large general customers billed under any Below-The-Line rates, other than the Shore Power rate. For customers billed under the Shore Power rate, the distribution component of the bundled Shore Power rate would apply.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-20:

Reference: Distribution Tariff Draft and Attachments

Re page 15, Lines 1-6, how much of the $83.3 million relates to distribution and retail and what effect (in percentage terms) does its exclusion have on the revenue requirement of the proposed DT?

Response DR-20:

The fixed cost deferral of $83.3 million was determined in the 2013 GRA proceeding outside of the Cost of Service framework. The deferral represents the remaining portion of the total revenue requirements in test years 2013 and 2014, after accounting for a 3% annual increase in composite rates. The $83.3 million of fixed costs whose recovery through rates was deferred in years 2013-2014 is included in the Cost of Service.

NS Power does not have functional area-specific fixed cost deferral information on the basis of which it could determine a portion of the deferral attributable to distribution and retail.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-21:

Reference: Distribution Tariff Draft and Attachments

Re page 26, Lines 2-4, are not all RtR customers required to have the TOD meters?

Response DR-21:

Yes, NS Power recommends that all Renewable to Retail customers be required to have interval/time-of-day meters with remote polling capability.

The proposed differentiated rate treatment between residential customers billed under the non-TOD and TOD rates is based on the assumption, originally contemplated by NS Power, that no interval metering would be required for RtR customers. The text in the "Domestic Time of Day rates" section on pages 25 and 26 has not been updated to reflect a change in this assumption. With the Company's proposal that all RtR customers are required to have interval metering, there is no longer a need to differentiate residential customer charges between the non-TOD and TOD customers. All open access residential customers will be, therefore, proposed to continue to pay the same charge of $10.83. Any incremental operational costs associated with interval metering, undetermined at this point, will be proposed to flow through to energy charges.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-22:

Reference: Distribution Tariff Draft and Attachments

Re Distribution Tariff, Section 4 – Is this section necessary? For what purpose?

Response DR-22:

Section 4 of the draft Distribution Tariff states:

> The Distribution Tariff has been approved by the Board. Nothing contained in the Distribution Tariff shall be construed as affecting in any way the right of NS Power to unilaterally make application to the Board for a change in any rates (including the Distribution Tariff rates set out in Appendix A), terms and conditions, charges, classification of service, rules or regulations.

This section was included in the Distribution Tariff for consistency with our Open Access Transmission Tariff in which it is included in Section 9.0 with the intent of providing clarity to users with respect to NS Power's right to make application to the Board for changes in the Distribution Tariff's elements.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-23:

Reference: Distribution Tariff Draft and Attachments

Re Distribution Tariff, Section 7 – Does the last paragraph fit here, under the heading "Ns Power Responsibilities"?

Response DR-23:

No, the last paragraph should not be included in the Distribution Tariff Section 7, and has been deleted. The clause is properly located in the LRS Terms and Conditions document, in Section 8.1.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-24:

Reference: Distribution Tariff Draft and Attachments

Re Appendix A, please provide derivation of minimum monthly charge of $17.51.

Response DR-24:

Starting with the 2013 GRA, NS Power has increased the minimum charge of the Miscellaneous Small Load rate commensurate with the overall increase in the unmetered base cost rates (electric service component before fixture capital and maintenance). The charge of $17.51 is the outcome of the cumulative effect of three rate increases:

1. 2012 GRA: $12.65 * 1.0981 = $13.89
2. 2013 GRA (2013 test year): $13.89 * 1.1722 = $16.28
3. 2013 GRA (2014 test year): $16.28 * 1.0757 = $17.51

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-25:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide the derivation of all charges in the EBS tariff.

Response DR-25:

Please refer to **Attachment 1**, also provided electronically, for derivation of the administration charge, energy charge and monthly energy credit. The avoided cost results are preliminary at this stage. Some of the cost and load figures are estimates at this stage and are used for illustrative purposes.

The proposed year-end refund to the Company for excess spill has been designed to align directionally with the perceived progression in costs of displaced generation, but is not rooted in actual cost analysis at this point. The Company is in the process of conducting an analysis of displaced costs at various RtR service uptake levels using Plexos. Upon completion, the Company will review and refine the calculation.

Energy Balancing Service: Administration Charge Calculations

Assumptions
(1) One Full Time Equivalent is sufficient to provide admin service in the initial market opening
(2) Assume 4 Licensed Service Providers. Note that this approach aligns with that used under the current Backup/Top-up Tariff.
(3) Admin costs to be shared equally between Energy Balancing and Standby Services

Full Time Equivalent (FTE) Cost

Salary		58,098
Fringe Benefits	16.0%	$9,296
Salary (including fringe benefits)		$67,394
Administrative Overhead	50%	$33,697
Forecast Cost		$101,090.88

Administration Charge Under Energy Balancing Service

Customer Charge Under BackUp Rate

Annual Cost (50% of total)	$50,545
Number of LRS	4
Monthly Administration Charge	**$1,053.03**

Standby Service: Customer Charge Calculations

Full Time Equivalent (FTE) Cost

Salary		58,098
Fringe Benefits	16.0%	$9,296
Salary (including fringe benefits)		$67,394
Administrative Overhead	50%	$33,697
Forecast Cost		$101,091

Administration Charge Under Standby Service

Annual Cost (50% of total)	$50,545
Number of LRS	4
Monthly Administration Charge	**$1,053.03**

Item # **Annual Avoided Fuel Cost Calculations**

Item #	Source		Annual GWh Load	Cost	Avoided Unit Cost (c/kWh)	Comments/Assumptions
		Avoided Costs				
1	Plexus Simulations	Avoided Costs of departing customer Load before taking energy balancing service from NS Power.	219	$13,052,400	5.960	Going forward the Company intends to use forecast load and hourly loadshape of customers served in the RtR market. For the purposes of this simulation the Company used flat 25 MW decrement.
2	Plexus Simulations	Avoided Costs of departing customer Load after taking energy balancing service from NS Power	219	$11,541,300	5.270	Going forward the Company intends to use NS Power's system hourly loadshape which will reflect the combined effect of hourly load of departing customers to the RtR market and 3rd party renewable generation under assumption that some of it may be curtailed. For the purposes of this simulation the Company used only the effect of 3rd party renewable generation under no curtailment assumption.
3		Cost Differential between items 1 and 2 above		$1,511,100		This is an incremental fuel cost arising from provision of energy balancing service to departed customers
4		**Spill Energy Credit rate**			5.270	Set at par with unit avoided costs under item #2.
5		**Top-up Energy Rate Calculation**				
5.1		**Avoided Fuel Cost Component**				
5.1.1		Average avoided cost after energy balancing service			5.270	Set at par with unit avoided costs under item #2.
5.1.2		Incremental costs associated with energy balancing service	109.5	$1,511,100	1.380	Going forward the Company intends to use forecast annual top-up energy in the RtR market in calculation of this charge. For now a simplifying assumption was made that top-up energy accounts for 50% of the total energy consumed in the RtR market (219 GWh/2 = 109.5 GWh)
		Fuel Cost charge			**6.650**	
4.2		**Energy-related fixed cost Component**				
	Appendix C 2014 COS Costs - Exhibit 5, page 1 Energy - Exhibit 9A, line 11, col 1.	Fixed Energy-related Cost in '000's of $ Charge in cents per kWh	9,116,236	$314,631,000	3.451	Calculated as follows: total of $753,049 less fuel of $367,943, purchased power regular of $507, purchased biomass power $11595, purchased wind power of $59,982, purchased imports of $217; plus export sales of $1,826
		Total top-up charge in cents per kWh			**10.101**	

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-26:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide the basis for the proposed spill payment and discounts in the EBS.

Response DR-26:

Please refer to Multeese DR-25.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-27:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

With respect to the EBS APPLICABILITY Clause 4, would it make sense to replace this clause with some reference to Board regulations that address this, to ensure consistency (particularly considering that the Board regulation on this issue is still under development)?

Response DR-27:

The EBS Availability Clause (4) states:

> To qualify for this service, the LRS must ensure that low impact renewable generation meets the kWh energy needs of its customers on an annual basis. This requires that top-up energy not exceed spill energy on an annual basis.

The Company concurs with Multeese's suggestion and proposes the following changes to the wording of Clause (4):

> To qualify for this service, the LRS must ensure that the imbalance between low impact renewable generation and energy consumption over the established compliance period conforms to Section 10 of the Board-approved Regulation.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-28:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

With respect to the two components of the SS identified on page 1, please identify each of these in the formula proposed for the calculation of the Monthly Standby Contract Demand.

Response DR-28:

The description of the two components of SS on page 1 is intended to provide information about the reasons for the service, but not a description of two separate rate formula elements. The proposed formula does not differentiate between the capacity adequacy service during RtR generator outages and the delivery of top-up service.

NON-CONFIDENTIAL

Request DR-29:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide the derivation of all charges in the SS tariff.

Response DR-29:

Please refer to **Attachment 1**, also provided electronically, for the derivation of the demand charge. For the derivation of the administration charge please refer to Multeese DR-25 Attachment 1.

Source	Category				Comments/ Assumptions
	Demand-related Costs	**Cost in thousands of $'s**			
Appendix C 2014 COS Costs - Exhibit 5, page 1, column 2.	**Demand-related fixed gen costs net of fuel costs**		$167,212		Calculated as follows: total of $176,854 k less purchased power regular of $390 k, purchased biomass power $2,205 k, purchased wind power of $7,048 k
GRA 2013 DE-03 - DE-04 Appendix L Attachment 3 pages 7 and 8, Figures 3-7 and 3-8	**Less: Ancillary generation-related costs recovered under OATT**				
	Reactive Supply & Voltage Control	$4,329			
	Regulation & Frequency	$5,092			
	Load Following	$18,225			
	Operating Reserve - Spinning (10 min)	$3,908			
	Operating Reserve - Supplemental (10 min)	$7,785			
	Operating Reserve - Supplemental (30 min)	$6,598			
		$45,937			
	Demand-related fixed Gen. Costs net of Ancillary Service Costs3		$121,275		

Source	**Capacity Usage in kW**	**Sum of 3 Coincident Winter Peaks At Generator's Gate**	**3CP Monthly Ave**	**At 69 kV Transmission**
	Transmission Loss at 69 kV			3.2%
Appendix C 2014 COS Costs - page 65 of 80, Exhibit 9A, col 10.	(1) DOMESTIC	3,327,702	1,109,234	1,074,881
	(2) SMALL GENERAL	123,720	41,240	39,963
	(3) GENERAL	1,361,828	453,943	439,884
	(4) GENERAL LARGE	161,337	53,779	52,114
	(5) SMALL INDUSTRIAL	116,650	38,883	37,679
	(6) MEDIUM INDUSTRIAL	225,735	75,245	72,915
	(7) LARGE INDUSTRIAL	318,264	106,088	102,802
	(8) ELI 2P-RTP	0	0	0
	(9) MUNICIPAL	122,088	40,696	39,436
	(10) UNMETERED	69,089	23,030	22,316
		5,826,414	1,942,138	1,881,990

Standby Demand Charge Calculation	**Cost**	**Usage**	**Unit Cost per kW**
Annual Rate per kW demand at 69 kV Voltage	$121,275.45	1,881,990	$64.440
Monthly Rate per kW demand at 69 kV Voltage			$5.370

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-30:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide the rationale for the formula proposed to calculate the Monthly Standby Contract Demand.

Response DR-30:

NS Power is a winter peaking utility; its investment in its generation capacity is determined on the basis of winter system peak. Accordingly, rate class responsibilities for the demand-related generation costs are determined in the Cost of Service Studies through their weighted average contribution to the three winter peaks of January, February and December. For rate classes billed under demand charges these costs are primarily recovered through monthly demand charges applicable to non-coincident monthly metered demands. For rate classes whose usage is billed only under energy charges these costs are recovered through monthly energy charges.

In both cases it is necessary for the Company to be able to reliably predict a test year class usage. This pricing model cannot be applied in the context of the RtR market because this information cannot be reliably determined.

It is expected that customers will switch between bundled and RtR services, and among LRSs, at any time of year. In addition, in the early stages of the RtR market opening, the Company expects a continued increase in customer participation in the RtR market but is not able to predict it with a level of accuracy required for rate setting purposes.

The historical peak demands of an LRS in December, January and February will likely be unrepresentative of the customer portfolio partway through the calendar year. The LRS historic winter demand may not even be available for a better part of the first year of its operation if the LRS commences service in non-winter months.

In order to reflect load changes to the LRS portfolio over the year, the Company proposes to recalculate an equivalent annual coincident demand on the basis of each month's actual peak coincident demand for the LRS portfolio. The calculation of this equivalent annual peak will reflect the differing load profiles of each customer class.

Just as the LRS's load may vary over the year, so may its generation resources, particularly as generation comes on line following the RtR market opening. It is therefore necessary to recognise firm dependable generation capacity on the basis of resources becoming available each month.

The Company proposes that the billing demand of an LRS be calculated as follows:

1. To determine the firm dependable capacity requirement associated with that LRS's load:

   (i) determine in each month the system peak firm demand hour;

   (ii) determine for that hour the total LRS load (excluding interruptible load) in each customer class, including distribution system losses;

   (iii) apply the applicable adjustment factor to derive the equivalent contribution to the weighted average of three system firm peaks of January, February and December for each class;

   (iv) aggregate the class equivalent annual contributions to determine the LRS total equivalent coincident peak firm demand;

NON-CONFIDENTIAL

2. Determine the dependable capacity contribution provided by the LRS's owned and contracted generation as the sum of contributions of firm dependable capacity of those generation facilities. Recognising the requirement for 20% reserve over coincident peak firm load, divide the firm dependable capacity by (1 + 20%) to arrive at the quantity of the LRS's equivalent coincident peak firm demand that is supported by the LRS's own firm dependable capacity.

3. Determine the billing demand of the LRS as the excess of the LRS's equivalent coincident peak firm demand associated with the LRS's load under #1 above over the quantity supported by the firm dependable capacity provided by the LRS's owned and contracted generation under #2 above.

4. If the quantity supported by the firm dependable capacity provided by the LRS exceeds the LRS's equivalent coincident peak firm demand, there is no payment.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-31:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide the derivation of the Class Monthly Demand Adjustment Factors.

Response DR-31:

Please refer to **Attachment 1**, also provided electronically.

EXHIBIT 9C

NOVA SCOTIA POWER INC.

DETAIL OF MONTHLY CLASS SYSTEM COINCIDENT KW DEMAND

FOR THE YEAR ENDING DECEMBER 31, 2014

MONTH	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUST.	(7) MEDIUM INDUST.	(8) LARGE INDUST.	(10) MUNICIPAL	(11) UNMETERED	(12) MERSEY SYSTEM	(13) GRLF	(14) REAL TIME PRICING	(15) LRT
(1) JANUARY	**1,964,311**	**1,104,057**	**43,147**	**486,923**	**53,307**	**41,413**	**75,544**	**99,525**	**40,866**	**19,648**	**0**	**-119**	**0**	**0**
(2) FEBRUARY	**1,981,599**	**1,173,908**	**40,667**	**431,736**	**52,870**	**39,011**	**73,290**	**103,535**	**42,022**	**24,524**	**0**	**38**	**0**	**0**
(3) MARCH	1,703,830	916,421	43,848	451,054	54,668	39,330	66,321	94,790	34,721	2,689	0	-12	0	0
(4) APRIL	1,487,479	828,353	24,511	358,217	47,826	33,707	65,546	97,816	28,440	2,904	0	159	0	0
(5) MAY	1,355,817	651,803	35,218	367,903	56,740	43,146	71,137	101,700	24,276	3,168	0	726	0	0
(6) JUNE	1,309,156	679,292	27,446	320,523	47,104	33,847	68,575	104,904	24,831	2,664	0	-29	0	0
(7) JULY	1,271,920	472,812	39,874	423,318	66,270	43,029	77,215	117,200	26,605	3,141	0	2,457	0	0
(8) AUGUST	1,353,115	526,585	37,826	436,203	69,731	41,855	73,583	119,528	26,796	3,002	0	18,006	0	0
(9) SEPTEMBER	1,365,156	532,092	35,370	442,411	69,677	39,462	73,306	119,016	27,554	2,855	0	23,413	0	0
(10) OCTOBER	1,382,088	657,260	31,104	381,063	56,167	42,855	74,543	107,711	27,449	2,430	0	1,506	0	0
(11) NOVEMBER	1,588,273	855,786	33,410	379,930	52,855	35,226	72,943	87,753	32,527	17,812	0	20,031	0	0
(12) DECEMBER	**1,880,818**	**1,049,737**	**39,906**	**443,170**	**55,161**	**36,226**	**76,901**	**115,203**	**39,201**	**24,917**	**0**	**396**	**0**	**0**
(13) TOT. SUMMED DMD.	18,643,563	9,448,108	432,327	4,922,450	682,375	469,107	868,902	1,268,681	375,288	109,755	0	66,571	0	0
(14) 3 C/P DEMANDS	**5,826,729**	**3,327,702**	**123,720**	**1,361,828**	**161,337**	**116,650**	**225,735**	**318,264**	**122,088**	**69,089**	**0**	**315**	**0**	**0**
(14) 3 C/P AVE DEMANDS	1,942,243	1,109,234	41,240	453,943	53,779	38,883	75,245	106,088	40,696	23,030	-	105	-	

RATIOS OF AVERAGE OF 3 WINTER MONTH COINCIDENT PEAKS TO MONTHLY COINCIDENT PEAKS

MONTH	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUST.	(7) MEDIUM INDUST.	(8) LARGE INDUST.	(10) MUNICIPAL	(11) UNMETERED	(12) MERSEY SYSTEM	(13) GRLF
(1) JANUARY	0.99	1.00	0.96	0.93	1.01	0.94	1.00	1.07	1.00	1.17	-	0.88
(2) FEBRUARY	0.98	0.94	1.01	1.05	1.02	1.00	1.03	1.02	0.97	0.94		2.79
(3) MARCH	1.14	1.21	0.94	1.01	0.98	0.99	1.13	1.12	1.17	8.56	-	8.62
(4) APRIL	1.31	1.34	1.68	1.27	1.12	1.15	1.15	1.08	1.43	7.93		0.66
(5) MAY	1.43	1.70	1.17	1.23	0.95	0.90	1.06	1.04	1.68	7.27		0.14
(6) JUNE	1.48	1.63	1.50	1.42	1.14	1.15	1.10	1.01	1.64	8.64	-	3.57
(7) JULY	1.53	2.35	1.03	1.07	0.81	0.90	0.97	0.91	1.53	7.33		0.04
(8) AUGUST	1.44	2.11	1.09	1.04	0.77	0.93	1.02	0.89	1.52	7.67		0.01
(9) SEPTEMBER	1.42	2.08	1.17	1.03	0.77	0.99	1.03	0.89	1.48	8.07		0.00
(10) OCTOBER	1.41	1.69	1.33	1.19	0.96	0.91	1.01	0.98	1.48	9.48		0.07
(11) NOVEMBER	1.22	1.30	1.23	1.19	1.02	1.10	1.03	1.21	1.25	1.29		0.01
(12) DECEMBER	1.03	1.06	1.03	1.02	0.97	1.07	0.98	0.92	1.04	0.92		0.26

RATIOS OF AVERAGE OF 3 WINTER MONTH COINCIDENT PEAKS TO AVERAGE SEASONAL COINCIDENT PEAKS

Jan, Feb, Dec	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Mar, Apr	1.22	1.27	1.21	1.12	1.05	1.06	1.14	1.10	1.29	8.24
May, June	1.46	1.67	1.32	1.32	1.04	1.01	1.08	1.03	1.66	7.90
Jul, Aug, Sep	1.46	2.17	1.09	1.05	0.78	0.94	1.01	0.89	1.51	7.68
Oct, Nov	1.31	1.47	1.28	1.19	0.99	1.00	1.02	1.09	1.36	2.28

Classes	Jan, Feb, Dec	Mar, Apr	May, June	Jul, Aug, Sep	Oct, Nov
Domestic	1.00	1.27	1.67	2.17	1.47
Small General	1.00	1.21	1.32	1.09	1.28
General	1.00	1.12	1.32	1.05	1.19
Large General	1.00	1.05	1.04	0.78	0.99
Small Industrial	1.00	1.06	1.01	0.94	1.00
Medium Industrial	1.00	1.14	1.08	1.01	1.02
Large Industrial Firm	1.00	1.10	1.03	0.89	1.09
Unmetered	1.00	8.24	7.90	7.68	2.28

NON-CONFIDENTIAL

Request DR-32:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide a numerical example of the application of the Monthly Standby Contract Demand formula, assuming an LRS supplying customers in each of the Residential, Small General and General classes from two wind turbines. Please identify all assumptions made with respect to the number of customers being served by the LRS in each rate class, aggregate customers' loads and load shapes by class, assumptions made with respect to the size of the wind turbines and their contribution to firm capacity, and any other assumptions necessary to provide this example. Of the assumptions, please identify those that would be metered if this example were real.

Response DR-32:

Please refer to **Attachment 1**, provided electronically.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-32:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide a numerical example of the application of the Monthly Standby Contract Demand formula, assuming an LRS supplying customers in each of the Residential, Small General and General classes from two wind turbines. Please identify all assumptions made with respect to the number of customers being served by the LRS in each rate class, aggregate customers' loads and load shapes by class, assumptions made with respect to the size of the wind turbines and their contribution to firm capacity, and any other assumptions necessary to provide this example. Of the assumptions, please identify those that would be metered if this example were real.

Response DR-32:

Please refer to **Attachment 1**, provided electronically.

NON-CONFIDENTIAL

Request DR-33:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide the rationale for the creation of a new Schedule 4A in OATT to accommodate the GFS.

Response DR-33:

The current wholesale market approach to imbalance between supply and demand includes two elements:

1. scheduled hourly energy balancing service requirements, which are addressed by the existing Backup/Top-up/Spill (BUTUS) tariff; and

2. deviations of the actual hourly quantities from the scheduled hourly quantities, which are addressed by Schedule 4 of the OATT.

This two-part approach was not considered suitable for the RtR market for the following reasons:

(a) The expected diversity of RtR load over multiple delivery points from the transmission system would make hourly load forecasting too onerous. It would also have questionable value in that it would not alter total loads at each delivery point.

(b) The asymmetric nature of the top-up charge and spill credit under the proposed EBS tariff, with the top-up charges including energy-related fixed cost recovery, would yield a material incentive for an LRS to under-forecast its load at times of expected top-up. Such under-forecasting would lead to LRS avoidance of the energy-related fixed cost recovery and could adversely affect the NSPSO's system management and optimization.

NON-CONFIDENTIAL

(c) Settlement under the two-part approach would be significantly more complex than under the proposed RtR market approach.

Having determined that the Energy Balancing Service tariff should provide for settlement against actual metered imbalances only, NS Power had to give consideration to the implications with respect to the OATT Schedule 4. The application of Schedule 4 as it stands would result in overlapping settlement for the marginal energy cost of imbalances which would not be appropriate.

Accurate forecasting is important to the NSPSO in the management of the system. Whereas the load forecasting element has limited value, as noted above, due to the embedding of RtR loads at delivery points, the generation forecasting element remains important. Schedule 4A is designed to provide the forecasting incentive element of existing schedule 4, as applicable to the production from non-dispatchable RtR generation.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-34:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please discuss whether the fixed cost adder in the EBS includes the cost of the GFS.

Response DR-34:

The fixed cost adder in the EBS tariff does not include costs incurred by RtR generators in forecasting its generation.

The adder also does not include the cost to the Company associated with inaccurate generation forecasts provided by RtR generators. While such costs exist they are difficult to determine. The proposed compensation mechanism under Schedule 4A is aligned with the payment structure under *Generation Energy Imbalance for Non-Dispatchable Generators* in Schedule 4. Under both schedules generators see similar disincentives equivalent to 10% of marginal cost per each MWh falling outside of a deviation band of +/-10% (with a minimum deviation band of +/-2 MW). Please refer also to Multeese DR-33.

NON-CONFIDENTIAL

Request DR-35:

Further to Multeese DR-30:

(a) Please identify any adjustments NSPI anticipates making its Cost of Service model or its inputs to reflect RtR?

(b) It is noted at Lines 19-21 on page 1 that NSPI's current pricing model cannot be applied to RtR because test year class usage cannot be reliably predicted. Please elaborate on how the proposed adjustment of actual monthly demands to equivalent winter peak demands in the SS tariff addresses this issue, from both a cost allocation and a revenue perspective.

(c) Apart from the cost allocation and revenue perspectives, please identify any other aspects of RtR that would preclude using the actual monthly demands as the Monthly Standby Contract Demand.

Response DR-35:

(a) NS Power does not anticipate making any adjustments to the COS model for the rate setting purposes of this RtR proceeding. For General Rate Applications (GRA) filed in future with the benefit of RtR service uptake estimates, the Company expects to treat the RtR customer usage and revenues in the test year COS model in a manner similar to the treatment of below-the-line (BTL) rate classes. In planning for such future GRAs, the Company will prepare a forecast of RtR service uptake taking account of information included in Retail Suppliers' applications for licences and ongoing compliance filings. The RtR customer usage is expected to be separated in the Exhibit 9 series from the above-the-line (ATL) classes and reported in the below-the-line category, grouped by their original ATL classes. Similarly, anticipated revenues, to be recovered from RtR customers and suppliers, are expected to be treated as an offset to the revenue

NON-CONFIDENTIAL

requirement from the ATL classes. RtR revenue will be cost itemized in the Direct Expense category of exhibits 4 and 4A, as is the case with the BTL rate classes, today. In parallel with the above COS adjustments, the Company will adjust test year billing determinants by the bundled service ATL classes in its "Proof of Revenue" calculations. The Company will also have to adjust its estimates of fuel cost to recognise that the Company's generation requirements and thus the average unit fuel cost will need to reflect the impacts of energy provided as top-up and received as spill and the potential spread in the average marginal costs between these.

Once the CoS model is completed on this basis, it is recognised that it may indicate changes in allocated unit costs from those on which the RtR tariff charges are based. In this case, the RtR charges used for the calculation of BTL cost recovery will be adjusted on an iterative basis until there is proper reconciliation between the RtR charges and the corresponding allocated unit costs in the ATL calculation.

(b) The proposed adjustment of actual monthly demands to equivalent winter peak demands will ensure accurate recovery of utility costs as allocated on a fair basis, as long as the ATL customers supplied by LRSs have similar coincident factors[1] to those assumed in the GRA rate setting process for the bundled service customers.

With the coincident factors being equal, any differences between the actual and test year forecast of a number of departed customers and their kWh load make no difference to the recovery of utility costs, as far as the billing demand aspect is concerned[2], because the

[1] Coincident factors, for the purposes of this discussion, include two types of constructs

a) Ratios between monthly coincident demand and average winter peak demand as used in the Standby Service tariff
b) Ratios between non-coincident and coincident monthly demands of individual customers billed under demand charges implicit in test year rate setting process.

[2] Another factor that can affect the recovery of utility's costs is the distribution of migrating load by bundled service rate classes which vary in terms of their revenue to cost (R/C) ratios. The utility will under- or over-recover its costs to the extent the migrating load is skewed towards bundled service classes with R/C ratios above or below unity.

NON-CONFIDENTIAL

proposed RtR rates, inclusive of the revenues under the RtR Market Transition Tariff, are based on fully embedded costs.

In order to avoid inequity that could arise due to differences between the coincident factors of RtR customer groups in each class and the ATL averages for the customers in the classes from which they originate, the Company will monitor the coincident factors of RtR customers. If they differ from the ATL class averages, assumed in the test year COSS, and cause a material discrepancy in the recovery of utility's costs, the Company will propose mitigating measures. For example, a change to the class monthly adjustment factors to reflect the coincident factors of RtR customers in each class in contrast to their ATL class average statistics. If the need arises, these changes could be submitted in a rate application.

Please refer to part (c) for discussion of the more fundamental reasons for the selection of the equivalent winter peak demand methodology for this tariff, and the way in which this methodology provides proper cost allocation and revenue recovery.

(c) The level of Standby Service required by each LRS will be determined by its load and by the firm reliable capability of its generation. From a system adequacy perspective, the most critical measures of firm reliable capability and of peak demand are those applicable in the winter months in which the winter peak is likely to occur and when reserve margins are therefore expected to be at their tightest. The CoS model therefore adopts the winter peak (coincident peak) as the appropriate basis for allocating demand-related generation cost among Bundled Service customer classes. Demand-related generation costs will be allocated to the RtR customer group on the same basis.

The proposed Standby Service tariff and the proposed RtR Transition Tariff demand charge collectively provide for the allocation of cost to, and recovery of cost from, each LRS on that same basis. This differs from the approach in bundled service tariffs, where the charge determinant used as the basis for recovery from members of the class is typically different from the basis of cost allocation to the class as a whole.

Within this framework, the appropriate metric of the Standby Service determinant is therefore the excess of the winter peak demand of the LRS's portfolio over the corresponding demand supported by the self-supplied firm dependable capability of its generation. The proposed adjustment of actual monthly demands to equivalent winter peak demands for use as the Monthly Standby Contract Demand, before deducting the self-supplied firm dependable (winter) capability achieves the proper Standby Service recovery from each LRS.

Consideration was given to the alternative of a tariff based on the use of actual monthly peak customer demand of each LRS. There are three reasons why this was not adopted:

(i) Given accurate forecasts of RtR load in each customer class and RtR generation of each technology, it would theoretically be possible to determine the total standby cost properly allocated to the total RtR market load and demand portfolio (i.e. as aggregated across all LRSs). From this, it would be possible to determine an average rate per unit of LRS portfolio customer peak monthly demand for use as a rate. This would however be inequitable between LRSs. It would fail to recognise that different generation technologies have different relationships between installed capacity, energy production, and firm dependable capability. A single demand-based tariff could not reflect these differences between LRSs. An LRS whose generation has a high firm dependable capability relative to its energy generated would share in the costs arising from another LRS's low quantity of firm dependable capability.

(ii) The calculation of a monthly demand rate as described above would be highly dependent on the forecasts of generation and RtR market load and

NON-CONFIDENTIAL

demand. The rate thus determined would thus be subject to wide variation from year to year, particularly during a period of initial market uptake. Standby Service tariff charges by this methodology would be significantly less stable than under the tariff as proposed.

(iii) NS Power would not have confidence in the accuracy of forecasts during the initial years of the RtR market.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Port Hawkesbury Paper Data Requests

NON-CONFIDENTIAL

Request DR-1:

On the slide entitled "Proposed Design of EBS, NSPI states that the energy charge for top-up will include an annually adjusted fuel cost of 6.650 cents/kWh and fixed cost for fixed energy-related generation costs of 3.451 cents/kWh, and the Energy credit for spill will be 5.27 cents/kWh.

(a) Please confirm that the annually adjusted fuel cost is a forecast that will be changed annually and provide the supporting calculations for the 6.650 cents/kWh figure.

(b) Please provide the supporting calculation for the 5.27 cents/kWh energy credit for spill figure, and indicate whether this is also based on a forecast.

(c) Please provide an explanation as to why the fuel component of the energy charge for top-up is significantly higher than the energy credit for spill.

(d) Will the energy credit for spill also be subject to change on an annual basis, and if so, what process would be followed to change this figure?

(e) Is it NSPI's position that the fixed energy-related generation costs would not be incurred absent the energy balancing service? If not, please explain the rationale for including this cost in the energy charge for top-up, given that these costs would be incurred anyway.

Response DR-1:

(a-b) Confirmed. Please refer to Multeese DR-25 for supporting calculations.

(c) The variable cost element of top-up is higher than the variable cost credit for spill. There are a number of contributing factors:

(i) There is a non-fuel variable cost associated with the management of top-up and spill. This is added to the top-up rate but deducted from the spill credit.

(ii) Irrespective of the RtR generation profile, it can be expected that top-up will be required more often at times of above average RtR load which can reasonably be expected to coincide with above average system load (with a tendency for higher marginal generation cost), and spill will be more prevalent at times of below average RtR load which can reasonably be expected to coincide with below average system load (with a tendency for lower marginal generation cost). This effect will contribute to the variable top-up rate being higher than the spill credit.

(iii) There is a large quantity of wind generation already connected to and supplying, or committed for supply to, the Nova Scotia system. RtR wind generation will have a production profile strongly correlated with the production profile of this other existing or committed wind generation. RtR wind generation will therefore have high production, with a tendency to produce spill, at times of high system wind production and thus of low system marginal fuel cost. Top-up is likely to be required in respect of RtR wind generation at times of low system wind production, and thus of higher system marginal fuel cost.

(d) The energy credit will be changed on annual basis. Please refer to Multeese DR-25 for more details.

(e) The Company needs generation resources to deliver top-up service. In accordance with the Company's Cost of Service methodology, the total fixed costs of the generation resources required are classified into those recoverable from demand and recoverable from energy. The backup tariff addresses recovery of costs classified as recoverable from demand, and the energy balancing tariff addresses recovery of costs classified as recoverable from energy. The energy supplied under this tariff is top-up energy, and the

NON-CONFIDENTIAL

fixed cost recovery is therefore applicable to this quantity. There is no reduction in NS Power's fixed generation costs due to RtR spill, so there is no corresponding spill credit in respect of those fixed costs.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Port Hawkesbury Paper Data Requests

NON-CONFIDENTIAL

Request DR-2:

On the slide entitled "Proposed Design of Standby Service", NSPI states that the Non-coincident Billing demand will be replaced with a ratcheted Monthly Coincident Demand.

Please explain the rationale for the proposed change.

Response DR-2:

Please refer to Multeese DR-30.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Port Hawkesbury Paper Data Requests

NON-CONFIDENTIAL

Request DR-3:

Using a sample customer load, please provide a comparison for illustrative purposes that shows the costs a customer using NSPI's proposal for new Energy Balancing and Standby Services would pay versus the costs that a customer would pay using NSPI's existing approved tariffs. Please identify all assumptions and explain the rationale for the resulting differences in cost between the two approaches.

Response DR-3:

Please refer to Multeese DR-32 for sample revenue calculations under the bundled and unbundled rates for various rate classes over a period of one year. NS Power is not in a position to provide a comparison of costs for individual customers as it does not know what prices will be charged by Licensed Renewable Suppliers (LRS); other tariffs charged by NS Power to the LRS, except for the Distribution Tariff, are applied on aggregate basis to the LRS's load. Please refer to CA DR-3 for a discussion of the pricing flexibility of an LRS.

NON-CONFIDENTIAL

Request DR-1:

Specific Scenario Example #1: Distribution-Connected Service

Scotian WindFields Inc. would like to request that Nova Scotia Power Inc. provide example scenarios that include itemized lines for all envisioned tariffs and charges associated with Renewable to Retail service, based on Capacity of both Generation and Load.

Scotian WindFields Inc. would suggest the below parameters, that can be altered or added to, in order to accommodate the example scenarios:

Renewable Generator: 1.0 MW [Distribution Connected]
Renewable to Retail Customer Load: 1.0 MW [Distribution Connected on same substation]

Scenario i) Hourly Generation is at 0.5 MW while Hourly Load is at 1.0 MW
Scenario ii) Hourly Generation is at 1.0 MW while Hourly Load is at 0.5 MW
Scenario iii) Hourly Generation is at 1.0 MW while Hourly Load is at 1.0 MW

For clarity, Scotian WindFields Inc. would like the below tariffs and charges itemized, even if there are no costs incurred for each example scenario. These include, but are not limited to:

- **All Distribution Tariffs and Charges**
- **All Back-Up, Top-Up and Spill Tariffs and Charges**
- **All NS Power Balancing Service Tariffs and Charges**
- **All NS Power Standby Service Tariffs and Charges**
- **All Associated OATT Tariffs and Charges**

NON-CONFIDENTIAL

Response DR-1:

Please refer to **Attachment 1**, also provided electronically.

DR-1 Generator Distribution Connected

Assumptions and Fixed Inputs		Value
Energy Balancing Service	Top Up rate ¢/kWh	10.101
Energy Balancing Service	[7]Spill rate ¢/kWh	5.27
Standby Services Tariff	GC = Generator Capacity (MW)	1.0
Standby Services Tariff	[8]CC = capacity contribution factor	0.17
Standby Services Tariff	Demand Charge per mo. Per kW	$ 5.37
PR (Planning Reserve)	(NPCC planning criteria)	20%
Average hours per month	=365*24/12	730
System Ave. Loss Factor	(from NS Power OASIS site)	2.28%
Distribution Losses	(from 2014 COSS - domestic dist losses: Feb)	7.70%

Assumptions:

[1]Assumes each scenario considered to occur in a different month
[2]Transmission losses assumed at 2.28% and Dist. losses assumed at 7.7%
[3]Assumes quantities as metered at the generator output and at the distribution load.
[4]Assume load as metered is a peak for the month and occurs in a winter month (Jan/Feb/Dec), CMDAF= 1.0
[5]Assume Distribution connected load is 100% Domestic class
[6] Includes all ancillary services
[7]Assumes annual excess spill quantity in the range of 0%-10% of annual LRS load
[8]Assumes renewable generator is a wind generator
[9]Assumes customer load as firm load with peak occurring coincident with system firm load
[10]Assumes that the Generation facility is suitable sized to meet the contracted amount of annual LRS RtR energy, i.e. GC=MSC (Maximum Spill Capacity).
[11]No Embedded Cost Recovery Charges are included in these calculations
[12]Average Domestic Customer load is 2.5 kW (Winter example)

	DR-1 Generator Distribution Connected		
	Note: each scenario considered to occur in a different month		
	Scenario i)	Scenario ii)	Scenario iii)
Renewable Generator Capacity[10]	1.0	1.0	1.0
Hourly Generation (MW)[3]	0.5	1.0	1.0
Generation adjusted for losses[2]	0.489	0.978	0.978
Customer Load on Distribution Sub. A (MW)[3]	1.0	0.5	1.0
LRS Aggregate Load adjusted for distribution losses[2]	1.077	0.539	1.077
Number of Customers[12]	431	215	431
LRS Aggregate customer load (MWh) in the hour	1.077	0.539	1.077
Top Up MWh delivered by NS Power in the hour	0.588	0.000	0.099
Spill MWh received by NS Power in the hour	0.000	-0.439	0.000

1 EBS Charges

Note: EBS hourly Top-up and Spill quantities are determined at the delivery point from the transmission system

	Scenario i)	Scenario ii)	Scenario iii)
Charges for Top Up MWh delivered by NS Power in the hour	$ 59.41	$ -	$ 10.03
Credits for Spill MWh received by NS Power in the hour	$ -	$ (23.15)	$ -
EBS Administration Charge applicable to the hour ($1053.03/730 hours)	$ 1.44	$ 1.44	$ 1.44
Total EBS	**$ 60.85**	**$ (21.70)**	**$ 11.47**

2 Standby Services Charges

		Scenario i)	Scenario ii)	Scenario iii)
	CMPFD[4,9]	1.077	0.539	1.077
(from Table in SS Tariff)	CMDAF[4]	1.000	1.000	1.000
	LWPFD	1.077	0.539	1.077
	CC*GC/(1+PR)[8]	0.142	0.142	0.142
	Min (LWPFD,CC*GC/(1+PR)	0.142	0.142	0.142
	MSCD (MW)	0.935	0.397	0.935

	Scenario i)	Scenario ii)	Scenario iii)
Standby Demand Charge applicable in the hour	$ 6.88	$ 2.92	$ 6.88
Standby Services Admin. Charge applicable to the hour ($1053.03/730 hours)	$ 1.44	$ 1.44	$ 1.44
Total SS	**$ 8.32**	**$ 4.36**	**$ 8.32**

DR-1 Generator Distribution Connected

Assumptions and Fixed Inputs		Value
Energy Balancing Service	Top Up rate ¢/kWh	10.101
Energy Balancing Service	[7]Spill rate ¢/kWh	5.27
Standby Services Tariff	GC = Generator Capacity (MW)	1.0
Standby Services Tariff	[8]CC = capacity contribution factor	0.17
Standby Services Tariff	Demand Charge per mo. Per kW $	5.37
PR (Planning Reserve)	(NPCC planning criteria)	20%
Average hours per month	=365*24/12	730
System Ave. Loss Factor	(from NS Power OASIS site)	2.28%
Distribution Losses	(from 2014 COSS - domestic dist losses: Feb)	7.70%

Assumptions:

[1]Assumes each scenario considered to occur in a different month
[2]Transmission losses assumed at 2.28% and Dist. losses assumed at 7.7%
[3]Assumes quantities as metered at the generator output and at the distribution load.
[4]Assume load as metered is a peak for the month and occurs in a winter month (Jan/Feb/Dec), CMDAF= 1.0
[5]Assume Distribution connected load is 100% Domestic class
[6] Includes all ancillary services
[7]Assumes annual excess spill quantity in the range of 0%-10% of annual LRS load
[8]Assumes renewable generator is a wind generator
[9]Assumes customer load as firm load with peak occurring coincident with system firm load
[10]Assumes that the Generation facility is suitable sized to meet the contracted amount of annual LRS RtR energy, i.e. GC=MSC (Maximum Spill Capacity).
[11]No Embedded Cost Recovery Charges are included in these calculations
[12]Average Domestic Customer load is 2.5 kW (Winter example)

3 Distribution Tariff Charges[5]

				Based on quantities as metered at the distribution level		
Domestic	DT rate		2.541 ¢/kWh	$ 25.410	$ 12.705	$ 25.410
	Fixed Customer Charge/mo./customer[12]	$	10.83	$ 6.391	$ 3.196	$ 6.391
			Total DT	**$ 31.80**	**$ 15.90**	**$ 31.80**

4 Transmission Tariff Charges[6]

		$/MW/Month	$/MW/hr	Based on LRS aggregate load in each Scenario		
Scheduling/Sys Control	Sch 1	$ 353.98	$ 0.4849	$ 0.52	$ 0.26	$ 0.52
Reactive Supply/Voltage	Sch 2	$ 182.76	$ 0.2504	$ 0.27	$ 0.13	$ 0.27
Regulation	Sch 3	$ 217.06	$ 0.2973	$ 0.32	$ 0.16	$ 0.32
Load Following	Sch 3	$ 776.85	$ 1.0642	$ 1.15	$ 0.57	$ 1.15
Spinning reserve	Sch 5	$ 166.58	$ 0.2282	$ 0.25	$ 0.12	$ 0.25
Op reserve 10 min.	Sch 6	$ 331.83	$ 0.4546	$ 0.49	$ 0.24	$ 0.49
Op reserve 30 min.	Sch 6	$ 281.23	$ 0.3852	$ 0.41	$ 0.21	$ 0.41
Network Trans service	Sch 10	$ 4,241.21	$ 5.8099	$ 6.26	$ 3.13	$ 6.26
			Total OATT	**$ 9.67**	**$ 4.83**	**$ 9.67**

5	**Total Tariff Charges for each specific hour under study[11]**	**$ 110.64**	**$ 3.39**	**$ 61.26**

NON-CONFIDENTIAL

Request DR-2:

Specific Scenario Example #2: Transmission-Aggregated Service

Scotian WindFields Inc. would like to request that Nova Scotia Power Inc. provide example scenarios that include itemized lines for all envisioned tariffs and charges associated with Renewable to Retail service, based on Capacity of both Generation and Load.

Scotian WindFields Inc. would suggest the below parameters, that can be altered or added to, in order to accommodate the example scenarios:

Renewable Generator: 15.0 MW [Transmission Connected]
Renewable to Retail Customer Load#1: 5.0 MW [Distribution Connected on Substation A]
Renewable to Retail Customer Load#2: 5.0 MW [Distribution Connected on Substation B]
Renewable to Retail Customer Load#3: 5.0 MW [Distribution Connected on Substation C]

Scenario i)
- **Hourly Generation is at 15.0 MW;**
- **Hourly Customer Load #1 is at 5.0 MW**
- **Hourly Customer Load #2 is at 5.0 MW**
- **Hourly Customer Load #3 is at 5.0 MW**

Scenario ii)
- **Hourly Generation is at 10.0 MW**
- **Hourly Customer Load #1 is at 1.0 MW**
- **Hourly Customer Load #2 is at 5.0 MW**
- **Hourly Customer Load #3 is at 5.0 MW**

Scenario iii)

- **Hourly Generation is at 15.0 MW**
- **Hourly Customer Load #1 is at 1.0 MW**
- **Hourly Customer Load #2 is at 5.0 MW**
- **Hourly Customer Load #3 is at 1.0 MW**

For clarity, Scotian WindFields Inc. would like the below tariffs and charges itemized, even if there are no costs incurred for each example scenario. These include, but are not limited to:

- **All Distribution Tariffs and Charges**
- **All Back-Up, Top-Up and Spill Tariffs and Charges**
- **All NS Power Balancing Service Tariffs and Charges**
- **All NS Power Standby Service Tariffs and Charges**
- **All Associated OATT Tariffs and Charge**

Response DR-2:

Please refer to **Attachment 1**, also provided electronically.

DR-2 Generator Transmission connected

Assumptions and Fixed Inputs

			Value
Energy Balancing Service		Top Up rate ¢/kWh	10.101
Energy Balancing Service		[7]Spill rate ¢/kWh	5.27
Standby Services Tariff		GC = Generator Capacity (MW)	15 MW
Standby Services Tariff		[8]CC = capacity contribution factor	0.17
Standby Services Tariff		Demand Charge per mo. Per kW $	5.37
PR (Planning Reserve)		(NPCC planning criteria)	20%
Average hours per month		=365*24/12	730
System Ave. Loss Factor	(from NS Power OASIS site)		2.28%
Distribution Losses		(from 2014 COSS - domestic dist losses: Feb)	7.70%

Assumptions:

[1]Assumes each scenario considered to occur in a different month
[2]Transmission losses assumed at 2.28% and Dist. losses assumed at 7.7%
[3]Assumes quantities as metered at the generator output and at the distribution load.
[4]Assume load as metered is a peak for the month and occurs in a winter month (Jan/Feb/Dec), CMDAF= 1.0
[5]Assume Distribution connected load is 100% Domestic class
[6] Includes all ancillary services
[7]Assumes annual excess spill quantity in the range of 0%-10% of annual LRS load
[8]Assumes renewable generator is a wind generator
[9]Assumes customer load as firm load with peak occurring coincident with system firm load
[10]Assumes Generation facility is sized to meet the contracted amount of annual LRS RtR energy, i.e. GC=MSC (Maximum Spill Capacity).
[11]No Embedded Cost Recovery Charges are included in these calculations
[12]Average Domestic Customer load is 2.5 kW (Winter example)

	DR-2 Generator Transmission connected		
	Note: each scenario considered to occur in a different month		
	Scenario i)	Scenario ii)	Scenario iii)
Renewable Generator Capacity[10]	15.0	15.0	15.0
Hourly Generation Capacity (MW)[3]	15.0	10.0	15.0
Generation adjusted for losses to transmission/distribution interface[2]	14.67	9.78	14.67
Metered Customer Load - Distribution Sub. A (MW)[3]	5.0	1.0	1.0
Metered Customer Load - Distribution Sub. B (MW)[4]	5.0	5.0	5.0
Metered Customer Load - Distribution Sub. C (MW)[5]	5.0	5.0	1.0
LRS Aggregate customer load MWh in the hour	15.0	11.0	7.0
LRS Aggregate Load adjusted for distribution losses[2]	16.16	11.85	7.54
Number of Customers[12]	6462	4739	3016
Top Up MWh delivered by NS Power in the hour	1.49	2.07	0.00
Spill MWh received by NS Power in the hour	0.00	0.00	-7.13

1 EBS Charges

Note: EBS hourly Top-up and Spill quantities are determined at the delivery point from the transmission system

	Scenario i)	Scenario ii)	Scenario iii)
Charges for Top Up MWh delivered by NS Power in the hour	$ 150.44	$ 209.08	$ -
Credits for Spill MWh received by NS Power in the hour	$ -	$ -	$ (375.57)
EBS Administration Charge applicable to the hour ($1053.03/730 hours)	$ 1.44	$ 1.44	$ 1.44
Total EBS	**$ 151.88**	**$ 210.52**	**$ (374.13)**

2 Standby Services Charges

		Scenario i)	Scenario ii)	Scenario iii)
	CMPFD[4,9]	16.16	11.85	7.54
(from Table in SS Tariff)	**CMDAF**[4]	1.0	1.0	1.0
	LWPFD	16.16	11.85	7.54
	CC*GC/(1+PR)[8]	2.13	2.13	2.13
	Min (LWPFD,CC*GC/(1+PR)	2.13	2.13	2.13
	MSCD (MW)	14.03	9.72	5.41

	Scenario i)	Scenario ii)	Scenario iii)
Standby Demand Charge applicable in the hour	$ 103.21	$ 71.52	$ 39.83
Standby Services Administration Charge applicable to the hour ($1053.03/730 hours)	$ 1.44	$ 1.44	$ 1.44
Total SS	**$ 104.65**	**$ 72.96**	**$ 41.27**

DR-2 Generator Transmission connected

Assumptions and Fixed Inputs

		Value
Energy Balancing Service	Top Up rate ¢/kWh	10.101
Energy Balancing Service	[7]Spill rate ¢/kWh	5.27
Standby Services Tariff	GC = Generator Capacity (MW)	15 MW
Standby Services Tariff	[8]CC = capacity contribution factor	0.17
Standby Services Tariff	Demand Charge per mo. Per kW $	5.37
PR (Planning Reserve)	(NPCC planning criteria)	20%
Average hours per month	=365*24/12	730
System Ave. Loss Factor	(from NS Power OASIS site)	2.28%
Distribution Losses	(from 2014 COSS - domestic dist losses: Feb)	7.70%

Assumptions:

[1]**Assumes each scenario considered to occur in a different month**
[2]**Transmission losses assumed at 2.28% and Dist. losses assumed at 7.7%**
[3]**Assumes quantities as metered at the generator output and at the distribution load.**
[4]**Assume load as metered is a peak for the month and occurs in a winter month (Jan/Feb/Dec), CMDAF= 1.0**
[5]**Assume Distribution connected load is 100% Domestic class**
[6] **Includes all ancillary services**
[7]**Assumes annual excess spill quantity in the range of 0%-10% of annual LRS load**
[8]**Assumes renewable generator is a wind generator**
[9]**Assumes customer load as firm load with peak occurring coincident with system firm load**
[10]**Assumes Generation facility is sized to meet the contracted amount of annual LRS RtR energy, i.e. GC=MSC (Maximum Spill Capacity).**
[11]**No Embedded Cost Recovery Charges are included in these calculations**
[12]**Average Domestic Customer load is 2.5 kW (Winter example)**

3 Distribution Tariff Charges[5]

			Based on quantities as metered at the distribution level		
Domestic	DT rate	2.541 ¢/kWh	$ 381.15	$ 279.51	$ 177.87
	Fixed Customer Charge/mo./customer[12]	$ 10.83	$ 95.868	$ 95.868	$ 95.868
		Total DT	**$ 477.02**	**$ 375.38**	**$ 273.74**

4 Transmission Tariff Charges[6]

		$/MW/Month	$/MW/hr	Based on LRS aggregate load in each Scenario		
Scheduling/Sys Control	Sch 1	$ 353.98	$ 0.4849	$ 7.83	$ 5.74	$ 3.66
Reactive Supply/Voltage	Sch 2	$ 182.76	$ 0.2504	$ 4.04	$ 2.97	$ 1.89
Regulation	Sch 3	$ 217.06	$ 0.2973	$ 4.80	$ 3.52	$ 2.24
Load Following	Sch 3	$ 776.85	$ 1.0642	$ 17.19	$ 12.61	$ 8.02
Spinning reserve	Sch 5	$ 166.58	$ 0.2282	$ 3.69	$ 2.70	$ 1.72
Op reserve 10 min.	Sch 6	$ 331.83	$ 0.4546	$ 7.34	$ 5.39	$ 3.43
Op reserve 30 min.	Sch 6	$ 281.23	$ 0.3852	$ 6.22	$ 4.56	$ 2.90
Network Transmission service	Sch 10	$ 4,241.21	$ 5.8099	$ 93.86	$ 68.83	$ 43.80
			Total OATT	**$ 144.99**	**$ 106.32**	**$ 67.66**

5	**Total Tariff Charges for each specific hour under study[11]**	**$ 878.54**	**$ 765.18**	**$ 8.54**

Renewable to Retail (NSUARB M06214)
NSPI Responses to Scotian WindFields Inc. Data Requests

NON-CONFIDENTIAL

Request DR-3:

Aggregation of Renewable to Retail Customers

Scotian WindFields Inc. would like to seek some clarity on how the scenario of aggregated Renewable to Retail customers will be addressed with respect to Back-up, Top-Up and Spill (BUTUS), and associated tariffs and charges.

If, for example, three (3) Renewable to Retail Customers held contracts with a single Licensed Renewable Supplier, would the Licensed Renewable Supplied be charged BUTUS tariffs and charged on a per-customer basis, or on an aggregated basis?

Scotian WindFields Inc. would also like to seek clarity in how location on different distribution systems or connection points may affect this aggregation.

Response DR-3:

The new Energy Balancing Service Tariff provides for provision of top-up energy and receipt of spill energy for the Renewable to Retail (RtR) market. The new Standby Services Tariff provides back-up service to the RtR market.

For Energy Balancing Services (top-up and spill), the energy charges or credits are determined based on the Licensed Renewable Supplier's (LRS) hourly load of its RtR customers after aggregation across all delivery points and its hourly generator injections aggregated across all receipt points.

Using the example in the question, where the three Renewable to Retail Customers held contracts with a single LRS, the LRS would be charged (or credited in the case of spill) for Energy Balancing Services on the basis of the aggregation of the three customers' hourly loads.

The hourly top-up and spill energy quantities are determined at the delivery point from the transmission system. Consequently, hourly load quantities for distribution connected RtR customers are adjusted by the addition of distribution losses. The LRS's hourly generation injections are adjusted by the deduction of transmission losses.

Top-up energy charges apply (after adjustments for losses as above) in any hour where aggregated customer load exceeds the RtR generation in that hour. Spill energy credits apply (after adjustments for losses as above) in any hour where the LRS's RtR generation in that hour exceeds aggregated customer load (subject to the maximum spill capacity).

For the Standby Service tariff, the billing determinant is the Monthly Standby Contract Demand and is determined using the customer load in each rate class after aggregation across all delivery points, after loss adjustment, and after application of the Class Monthly Demand Adjustment Factor.

The Energy Balancing Service Tariff and Standby Services Tariff each include a monthly administration charge based on the annual forecast administration charge for the tariffs apportioned amongst the subscribed LRSs.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Scotian WindFields Inc. Data Requests

NON-CONFIDENTIAL

Request DR-4:

Hourly Marginal Cost Forecasting

To best determine the overall economics and commercial operation and optimization for Renewable to Retail rates to perspective customers, Scotian WindFields Inc. requests confirmation if Licensed Retail Suppliers will have access to Hourly Forecasted Marginal Costs (similar to some existing customer classes).

Response DR-4:

No. The tariffs as proposed for the Renewable to Retail market do not rely on hourly forecasted marginal costs for determination of charges. Consequently, an LRS will not require this information.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Scotian WindFields Inc. Data Requests

NON-CONFIDENTIAL

Request DR-5:

Real-Time Metering and Data Access

Scotian WindFields Inc. requests confirmation if Licensed Retail Suppliers will have access to real-time, load data from each Renewable to Retail Customer that it will be contracted to supply; or if this scenario is envisioned in the current Renewable to Retail Framework.

Response DR-5:

Real time load data acquisition is not proposed to be implemented for the Renewable to Retail market. Metering data reports will be provided to the LRS to enable it to bill each of its RtR customers, and to support NS Power billing information.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Scotian WindFields Inc. Data Requests

NON-CONFIDENTIAL

Request DR-6:

Path Losses and Penalties

Scotian WindFields Inc. would like to inquire as to whether or not the penalties will be different of providing transmission-connected generation in separate areas of Nova Scotia. If, for example:

(a) LRS Generation is located within Halifax County, and the Renewable to Retail Customer is located within Cape Breton Regional Municipality or;

(b) LRS Generation is located within Cape Breton Regional Municipality, and the Renewable to Retail Customer is located within Halifax County.

For clarity, Scotian WindFields Inc. is looking to ensure that the LRS entity is not at risk for Incremental system losses based on location of a new generation resource in the case where Renewable Generation is built and interconnected on transmission and customers are distribution connected.

Response DR-6:

Under the OATT, Transmission Customers are required to provide the losses associated with their service and are required to include an amount of additional capacity in their service requests sufficient to carry the losses associated with their service. For generators serving multiple dispersed loads as described in the examples above, Network Integration Transmission Service would be applicable, and the System Average Transmission Loss Factor would apply regardless of the generator's geographical location in the province. The System Average Transmission Loss Factor for 2015 is 2.28% of load.

Appendices 13A-13F have been provided in electronic format only.

Purpose: Conference call to respond to stakeholder questions about NS Power's DR responses.

In attendance: Bill Ellis (NSP), Eric Ferguson (NSP), Voytek Grus (NSP), Brian Curry (NSP), Rob Cary (Consultant), Bruce Outhouse (counsel to UARB), Scott McCoombs (Department of Energy); Ron Seftel (Bullfrog Power), Stephen Thomas (Scotian Windfields); Stephen McGrath (Department of Justice); John Woods (Minas Energy); Jocelyn Fraser (UARB); Aaron Long (Minas Energy); David MacDougall (PHP)

Embedded Cost Recovery

David MacDougall:

- Review suggests there may be overlap in recovery of costs with the pending embedded cost recovery mechanism; seeking confirmation that none of the other items covered through other charges are duplicated.

NS Power response:

- Embedded costs tariff to be released tomorrow. Brief overview provided.

SWF DR-1

David MacDougall:

- Looking at the way the charges are being developed (top up and spill), looking for more clarity about the costs.

Multeese DR-32

David MacDougall:

- Looking at the Energy Balancing Summary Tab – total costs $32 /MWh (3.2 cents /kWh) show $32 MWh, but components are Distribution $12/MWh, OATT $12/MWh, Top-up / Spill $8/$MWh, and Demand $3/MWh . Those amounts add up to $35/MWh (3.5 cents/kWh); how did NSP arrive at 3.2 ($32/MWh)?

NS Power:

- $32 is the weighted average cost for the customer portfolio; transmission customers do not pay the distribution charge, so it is not appropriate to simply add up the charges.

- The overall total is weighted differently from the totals within the individual columns and is the total amounts divided by total kWh served.
- In DR-32 there is significant energy spill. In the RTR market EBS tab there is a spill of $4.5 million that helps to reduce the number. There will always be some spill.
- The purpose was to illustrate the working of the system in its entirety; the Company has proposed a sliding scale treatment for spilled energy. That's why there is an example that exceeds load to show how that would work.
- In SWF DR-1 and DR-2 the assumptions recognize that the type of load served will affect costs. Different classes drive different distribution costs in this scenario.
- The scenarios in DR-1 and DR-2 look at a particular hour, and one may show costs of $61 and another may be at -$3. The model in DR-32 is an accumulation of all the 8760 hours. To take a single hour may not necessarily be what would happen over a longer time frame, particularly if the generation is intermittent.

David MacDougall:

- Does the Company's example in response to DR-32 have more transmission-related charge than distribution-related charge?

NS Power:

- Yes; there are Large General and Medium Industrial customers who pay less for distribution in terms of units / kWh consumed, and that has its foundation in the Cost of Service design. There is a range of blended costs in distribution ranging from .5 cents (Large Industrial) to 4 cents (Residential).

David MacDougall:

- This scenario is not truly a scenario that a wind farm with a portfolio of residential customers would be charged; this is more of a transmission level scenario?

NS Power:

- It's more of a true general customer mix scenario rather than just residential load scenario as is the case with DR-1 and DR-2.

David MacDougall:

- DR-1 allows him to segregate the numbers out, which is helpful. Can take any mix of hours and segregate by spill and top-up. It has 3 scenarios: one with top-up, one with spill, and one with equivalents of generation and load.

Multeese DR-30

David MacDougall:

- Mel Whalen asked a follow-up question about putting a ratchet on one component of one of the charges. NS Power is asked if it can speak to the ratchet.

NS Power:

- NS Power estimates an average winter peak for the customer mix in each month and then applies rates predicated on that usage. In other words, the Company looks at average winter peak and multiplies x 12 and that is the usage that gives rise to the charge of $5.37.

Materials to issue to stakeholders

David MacDougall:

- It would be beneficial to have the response to DR-1 which shows the embedded costs charge. Is looking for whether NS Power can provide a ballpark figure which removes the embedded recovery costs.

NS Power:

Company undertakes to update SWFI DR-1 as quickly as possible. It will take a couple of days to vet. Tomorrow it will be sending the RTT and an updated DR-32.

DR-1 Generator Distribution Connected

Assumptions and Fixed Inputs		Value
Energy Balancing Service	Top Up rate ¢/kWh	10.101
Energy Balancing Service	[7]Spill rate ¢/kWh	5.27
Standby Services Tariff	GC = Generator Capacity (MW)	1.0
Standby Services Tariff	[8]CC = capacity contribution factor	0.17
Standby Services Tariff	Demand Charge per mo. Per kW	$ 5.37
PR (Planning Reserve)	(NPCC planning criteria)	20%
Average hours per month	=365*24/12	730
System Ave. Loss Factor	(from NS Power OASIS site)	2.28%
Distribution Losses	(from 2014 COSS - domestic dist losses: Feb)	7.70%
RTT demand charge	Demand Charge per mo. Per kW	$ 5.37
RTT energy charge	¢/kWh	3.451

Assumptions:

[1]Assumes each scenario considered to occur in a different month
[2]Transmission losses assumed at 2.28% and Dist. losses assumed at 7.7%
[3]Assumes quantities as metered at the generator output and at the distribution load.
[4]Assume load as metered is a peak for the month and occurs in a winter month (Jan/Feb/Dec), CMDAF= 1.0
[5]Assume Distribution connected load is 100% Domestic class
[6] Includes all ancillary services
[7]Assumes annual excess spill quantity in the range of 0%-10% of annual LRS load
[8]Assumes renewable generator is a wind generator
[9]Assumes customer load as firm load with peak occurring coincident with system firm load
[10]Assumes that the Generation facility is suitable sized to meet the contracted amount of annual LRS RtR energy, i.e. GC=MSC (Maximum Spill Capacity).
[11]RtR Transition Tariff Charges are included in these calculations
[12]Average Domestic Customer load is 2.5 kW (Winter example)

DR-1 Generator Distribution Connected

Note: each scenario considered to occur in a different month

	Scenario i)	Scenario ii)	Scenario iii)
Renewable Generator Capacity[10]	1.0	1.0	1.0
Hourly Generation (MW)[3]	0.5	1.0	1.0
Generation adjusted for losses[2]	0.489	0.978	0.978
Customer Load on Distribution Sub. A (MW)[3]	1.0	0.5	1.0
LRS Aggregate Load adjusted for distribution losses[2]	1.077	0.539	1.077
Number of Customers[12]	431	215	431
LRS Aggregate customer load (MWh) in the hour	1.077	0.539	1.077
Top Up MWh delivered by NS Power in the hour	0.588	0.000	0.099
Spill MWh received by NS Power in the hour	0.000	-0.439	0.000

1 EBS Charges

Note: EBS hourly Top-up and Spill quantities are determined at the delivery point from the transmission system

	Scenario i)	Scenario ii)	Scenario iii)
Charges for Top Up MWh delivered by NS Power in the hour	$ 59.41	$ -	$ 10.03
Credits for Spill MWh received by NS Power in the hour	$ -	$ (23.15)	$ -
EBS Administration Charge applicable to the hour ($1053.03/730 hours)	$ 1.44	$ 1.44	$ 1.44
Total EBS	**$ 60.85**	**$ (21.70)**	**$ 11.47**

2 Standby Services Charges

		Scenario i)	Scenario ii)	Scenario iii)
	CMPFD[4,9]	1.077	0.539	1.077
(from Table in SS Tariff)	**CMDAF[4]**	1.000	1.000	1.000
	LWPFD	1.077	0.539	1.077
	CC*GC/(1+PR)[8]	0.142	0.142	0.142
	Min (LWPFD,CC*GC/(1+PR)	0.142	0.142	0.142
	MSCD (MW)	0.935	0.397	0.935

	Scenario i)	Scenario ii)	Scenario iii)
Standby Demand Charge applicable in the hour	$ 6.88	$ 2.92	$ 6.88
Standby Services Admin. Charge applicable to the hour ($1053.03/730 hours)	$ 1.44	$ 1.44	$ 1.44
Total SS	**$ 8.32**	**$ 4.36**	**$ 8.32**

DR-1 Generator Distribution Connected

Assumptions and Fixed Inputs		Value
Energy Balancing Service	Top Up rate ¢/kWh	10.101
Energy Balancing Service	[7]Spill rate ¢/kWh	5.27
Standby Services Tariff	GC = Generator Capacity (MW)	1.0
Standby Services Tariff	[8]CC = capacity contribution factor	0.17
Standby Services Tariff	Demand Charge per mo. Per kW	$ 5.37
PR (Planning Reserve)	(NPCC planning criteria)	20%
Average hours per month	=365*24/12	730
System Ave. Loss Factor	(from NS Power OASIS site)	2.28%
Distribution Losses	(from 2014 COSS - domestic dist losses: Feb)	7.70%
RTT demand charge	Demand Charge per mo. Per kW	$ 5.37

Assumptions:

[1]Assumes each scenario considered to occur in a different month
[2]Transmission losses assumed at 2.28% and Dist. losses assumed at 7.7%
[3]Assumes quantities as metered at the generator output and at the distribution load.
[4]Assume load as metered is a peak for the month and occurs in a winter month (Jan/Feb/Dec), CMDAF= 1.0
[5]Assume Distribution connected load is 100% Domestic class
[6] Includes all ancillary services
[7]Assumes annual excess spill quantity in the range of 0%-10% of annual LRS load
[8]Assumes renewable generator is a wind generator
[9]Assumes customer load as firm load with peak occurring coincident with system firm load
[10]Assumes that the Generation facility is suitable sized to meet the contracted amount of annual LRS RtR energy, i.e. GC=MSC (Maximum Spill Capacity).
[11]RtR Transition Tariff Charges are included in these calculations
[12]Average Domestic Customer load is 2.5 kW (Winter example)

3 Distribution Tariff Charges[5]

			Based on quantities as metered at the distribution level		
Domestic	DT rate	2.541 ¢/kWh	$ 25.410	$ 12.705	$ 25.410
	Fixed Customer Charge/mo./customer[12]	$ 10.83	$ 6.391	$ 3.196	$ 6.391
		Total DT	**$ 31.80**	**$ 15.90**	**$ 31.80**

4 Transmission Tariff Charges[6]

		$/MW/Month	$/MW/hr	Based on LRS aggregate load in each Scenario		
Scheduling/Sys Control	Sch 1	$ 353.98	$ 0.4849	$ 0.52	$ 0.26	$ 0.52
Reactive Supply/Voltage	Sch 2	$ 182.76	$ 0.2504	$ 0.27	$ 0.13	$ 0.27
Regulation	Sch 3	$ 217.06	$ 0.2973	$ 0.32	$ 0.16	$ 0.32
Load Following	Sch 3	$ 776.85	$ 1.0642	$ 1.15	$ 0.57	$ 1.15
Spinning reserve	Sch 5	$ 166.58	$ 0.2282	$ 0.25	$ 0.12	$ 0.25
Op reserve 10 min.	Sch 6	$ 331.83	$ 0.4546	$ 0.49	$ 0.24	$ 0.49
Op reserve 30 min.	Sch 6	$ 281.23	$ 0.3852	$ 0.41	$ 0.21	$ 0.41
Network Trans service	Sch 10	$ 4,241.21	$ 5.8099	$ 6.26	$ 3.13	$ 6.26
			Total OATT	**$ 9.67**	**$ 4.83**	**$ 9.67**

5 RTT, scenario

Displaced capacity (MW)	0.142	0.142	0.142
Demand element of charge	$ 1.04	$ 1.04	$ 1.04
Displaced energy (MWh)	0.489	0.539	0.978
Energy element of charge	$ 16.87	$ 18.58	$ 33.74
Total RTT	$ 17.91	$ 19.63	$ 34.78

6 RtR charges / hr for scenario incl RTT

Energy Charges	$ 101.69	$ 8.14	$ 69.18
Demand Charges	$ 17.59	$ 8.79	$ 17.59
Customer / LRS Charges	$ 9.28	$ 6.08	$ 9.28
Total charges /hr for scenario	**$ 128.55**	**$ 23.02**	**$ 96.04**

7 RtR charge / customer MWhr incl RTT

Energy Charges	$ 101.69	$ 16.28	$ 69.18

DR-1 Generator Distribution Connected

Assumptions and Fixed Inputs		Value
Energy Balancing Service	Top Up rate ¢/kWh	10.101
Energy Balancing Service	[7]Spill rate ¢/kWh	5.27
Standby Services Tariff	GC = Generator Capacity (MW)	1.0
Standby Services Tariff	[8]CC = capacity contribution factor	0.17
Standby Services Tariff	Demand Charge per mo. Per kW	$ 5.37
PR (Planning Reserve)	(NPCC planning criteria)	20%
Average hours per month	=365*24/12	730
System Ave. Loss Factor	(from NS Power OASIS site)	2.28%
Distribution Losses	(from 2014 COSS - domestic dist losses: Feb)	7.70%
RTT demand charge	Demand Charge per mo. Per kW	$ 5.37

Assumptions:

[1]Assumes each scenario considered to occur in a different month
[2]Transmission losses assumed at 2.28% and Dist. losses assumed at 7.7%
[3]Assumes quantities as metered at the generator output and at the distribution load.
[4]Assume load as metered is a peak for the month and occurs in a winter month (Jan/Feb/Dec), CMDAF= 1.0
[5]Assume Distribution connected load is 100% Domestic class
[6] Includes all ancillary services
[7]Assumes annual excess spill quantity in the range of 0%-10% of annual LRS load
[8]Assumes renewable generator is a wind generator
[9]Assumes customer load as firm load with peak occurring coincident with system firm load
[10]Assumes that the Generation facility is suitable sized to meet the contracted amount of annual LRS RtR energy, i.e. GC=MSC (Maximum Spill Capacity).
[11]RtR Transition Tariff Charges are included in these calculations
[12]Average Domestic Customer load is 2.5 kW (Winter example)

Demand Charges	$ 17.59	$ 17.59	$ 17.59
Customer / LRS Charges	$ 9.28	$ 12.16	$ 9.28
Total RtR Charges /MWh incl RTT	$ 128.55	$ 46.03	$ 96.04

Appendix 14A has been provided in electronic format only.

Nova Scotia
POWER
An Emera Company

RENEWABLE TO RETAIL

Draft Renewable to Retail Market Transition Tariff

July 22, 2015

Renewable to Retail Market Transition Tariff (RTT)

THIS PROPOSED RTT IS COMPLEMENTARY TO TARIFFS AND OTHER DOCUMENTS NS POWER HAS ISSUED FOR STAKEHOLDER CONSULTATION

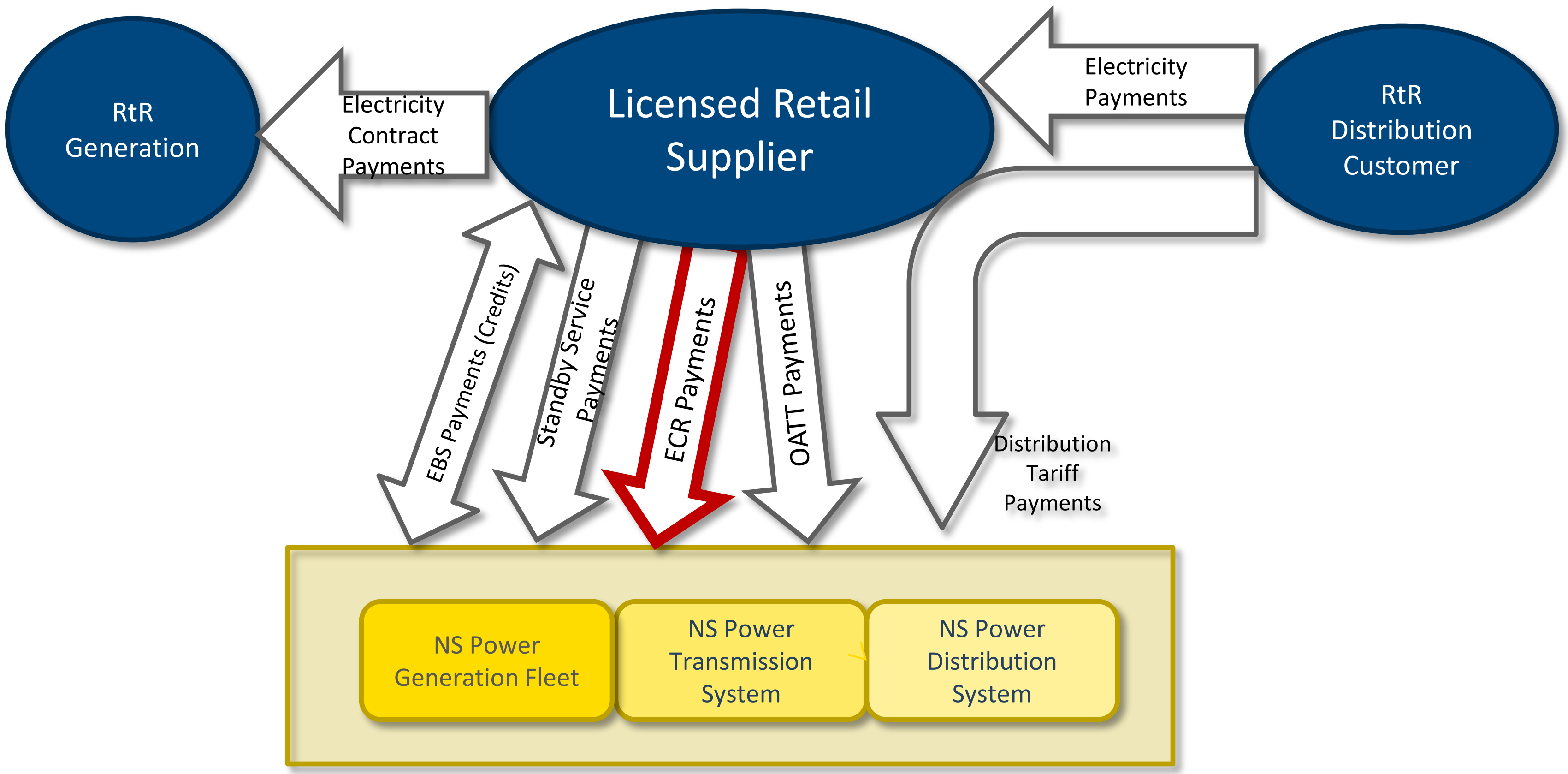
- Distribution Tariff
- Energy Balancing Services Tariff
- Standby Service Tariff
- OATT Schedule 4A (Generation Forecasting Service)
- LRS Terms and Conditions and Participation Agreement

Legislative Directive – Electricity Act

S 3G(2) IN REVIEWING AND APPROVING THE TARIFFS, PROCEDURES AND STANDARDS OF CONDUCT REQUIRED TO BE DEVELOPED OR AMENDED PURSUANT TO THIS SECTION, THE BOARD SHALL BE GUIDED BY THE FOLLOWING PRINCIPLES:

- (a) customers of Nova Scotia Power Incorporated and persons who, at the coming into force of this Section, are independent power producers or hold feed-in tariff approvals within the meaning of the regulations are not to be negatively affected if some retail customers choose to purchase renewable low-impact electricity from a retail supplier;
- (b) retail suppliers and their customers are to be responsible for all costs related to the provision of service by retail suppliers to their customers that would otherwise be the responsibility of Nova Scotia Power Incorporated and its customers.

Flow of Payments in the RtR Market



Nova Scotia POWER
An Emera Company

Rationale for Embedded Cost Recovery (ECR)

NS Power has developed its power system to meet the current and forecast requirements of all customers.

CUSTOMERS DEPARTING FROM BUNDLED SERVICE TO THE RTR MARKET WOULD, IN THE ABSENCE OF AN EMBEDDED COST RECOVERY (ECR) MECHANISM, CREATE A COST TRANSFER FROM RTR CUSTOMERS TO BUNDLED SERVICE CUSTOMERS.

THE ECR SHOULD RECOGNIZE UTILITY FIXED ASSETS AND COMMITMENTS AND DEFERRED COSTS.

- Fixed assets and commitments (e.g. PPAs), and deferred costs incurred by the Company have been prudently incurred and are recoverable from NS Power customers.

Embedded Costs: types and method of determination

TWO AREAS OF COST RECOVERY ARE AFFECTED BY CUSTOMER DEPARTURE:

- Fixed costs of generation (e.g. depreciation, cost of financing including return on common equity, income tax and OM&G)
- Deferred costs: Costs incurred in the delivery of past service for which recovery has been deferred by approval of the UARB (e.g. deferred DSM expenditures)

TO BE DETERMINED ON A GO-FORWARD BASIS COMMENSURATE WITH

- Displaced Sales of energy and capacity
- Changing costs of production
- Cost mitigation opportunities

Proposed Approach to ECR

- For any electricity NS Power supplies to LRS load, fixed and deferred costs are recovered within the EBS and SS rates.
- When NS Power is not supplying electricity to LRS load, fixed and deferred costs are recovered by the RTT.

Proposed Approach to ECR

THE TARIFF APPLIES TO EACH LRS

- The amount of embedded cost to recover
  - Depends on characteristics of RtR generation and load
  - Depends on LRS's usage of NSP Standby and Energy Balancing services.
- Therefore the tariff is the responsibility of each LRS in respect of its overall portfolio, not on a customer-specific basis.

Proposed RTT Rates

The tariff has two components, Demand Charge and Energy Charge.

- Note that past FAM costs are recovered separately per the FAM tariff.
- Updated Multeese DR-32 shows sample calculation

Energy Charge Components	Cents per kWh
Fixed Cost Adder from Energy Balancing Service Tariff	3.451
Annually Adjusted Energy Savings Credit	-
Annual Energy Cost Adjustment	-
Total	3.451

Demand Charge Components	Dollars per kW
Demand Charge from Standby Service Tariff	$5.370
Annually Adjusted Demand-related Fixed Cost Loss Mitigation Credit	$0.000
Total	$5.370

Proposed RTT framework

ENERGY CHARGE

- Recovery of fixed energy-related generation costs in respect of the top-up quantity is provided through the EBS.
- The RTT provides for recovery of the balance of energy-related generation fixed costs associated with the LRS's sales.
- This base rate is the same rate as in the Energy Balancing Service Top-up tariff based on Cost of Service.
- This base rate will be offset in part by an Annually Adjusted Energy Savings Credit, representing embedded energy-related cost mitigation achievable.

Proposed RTT framework

ENERGY CHARGE, ctd.

- Displacement of NS Power’s energy by RtR energy reduces NS Power’s costs by its avoided cost, but reduces its revenue by its average fuel cost.
- This Annual Energy Cost Adjustment is deducted from the base energy rate to get the net energy charge under the tariff. If the average fuel cost were to exceed the avoided cost, this Energy Charge Adjustment would become an addition to the net energy charge under the tariff.

Proposed RTT framework

DEMAND CHARGE

- Recognising that the Standby Service tariff will provide for recovery of fixed demand-related generation costs in respect of the standby quantity, the RTT provides for recovery of the balance of the contribution to system peak demand (the LRS's displaced demand). This base rate is the same rate as is used in the Standby Service tariff, and will be based on Cost of Service.

- This base rate will be reduced by a Demand-related Fixed Cost Loss Mitigation Credit, representing embedded demand-related cost mitigation achievable.

Example - ENERGY PORTION

	Situation	LRS Customer Load	LRS supply	EBS Top-up	EBS Spill	RTT energy portion recovery base	Rationale
		MWh/hr	MWh/hr	MWh/hr	MWh/h	MWh/hr	
1	LRS generation meeting customer load exactly	12	12	0	0	12	NS Power recovers RTT energy portion on the quantity of electricity it does not supply (the whole load)
2	LRS generating less than customer load	12	8	4	0	8	NS Power recovers RTT on the quantity of electricity it does not supply. Top-up recovers embedded costs on the 4 MWh/hr, so RTT energy portion only applies to the 8 MWh/hr of LRS supply.
3	LRS generating more than customer load	12	14	0	2	12	NS Power recovers RTT on the quantity of electricity it does not supply (the whole load), in this case, separately, the spill tariff also applies.
4	LRS generation offline, NS Power meeting customer load	12	0	12	0	0	NS Power is supplying the whole load; Standby and Top-up portion of EBS recover embedded costs, so the RTT energy portion = 0.

Example – DEMAND PORTION

	Situation	LRS Customer Load (winter peak)	LRS self-supply of firm reliable capacity ÷ 1.20	Standby Service	RTT demand portion recovery base	Rationale
		MW	MW	MW	MW	
1	LRS self-supply capacity matches requirement	15	15	0	15	NS Power recovers RTT on the quantity of the LRS's winter peak demand
2	LRS self-supply capacity less than requirement	15	8	7	8	NS Power charges Standby service on the quantity of the capacity requirement that the LRS does not self-supply. NS Power recovers RTT on the quantity of the capacity served by the LRS's self-supplied capacity
3	LRS self-supply capacity greater than requirement	15	20	0	15	NS Power recovers RTT on the quantity of the LRS's winter peak demand

Nova Scotia POWER
An Emera Company

Proposed RTT characteristics

SETTLEMENT

- Monthly settlement on the basis of the LRS's portfolio, consistent with NS Power's recovery of certain fixed costs through services provided.

MITIGATION

- NS Power mitigation of stranded costs, where this can be demonstrated and verified before the UARB, will be applied as a credit to the pre-mitigation rates.

ANNUALLY ADJUSTED

- The tariff will recognise the need to update such estimates annually on a forward looking basis.

Next steps

Stakeholder comments are requested by August 5, 2015.

PURPOSE

Pursuant to Section 3G(2) of the Electricity Act (Nova Scotia), the Renewable to Retail Market Transition Tariff (RTT) is designed to recover from Licensed Retail Suppliers (LRS) Nova Scotia Power Inc.'s (NS Power or Company) embedded fixed costs and deferred costs, recovered through bundled service, which are not otherwise recovered through other tariffs applicable to the LRS or its Retail customers. For certainty, for the purposes of this RTT, NS Power's embedded fixed costs include, but are not limited to, generation related fixed costs (e.g. depreciation, cost of financing including return on common equity, income tax and OM&G). Deferred costs of NS Power are those costs approved by the Nova Scotia Utility and Review Board (Board) for recovery by the Company from customers at a future date.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in NS Power's LRS Terms and Conditions.

APPLICABILITY

1. The RTT is applicable to the LRS, and is in addition to (and not in substitution of) any charges owing by the LRS to NS Power under the Open Access Transmission Tariff (OATT), the Standby Service Tariff or the Energy Balancing Service Tariff.

2. The RTT employs certain usage determinants and rate components applicable under both the Standby Service Tariff and the Energy Balancing Tariff.

3. Energy Charges and Demand Charges (both as set out below) under the RTT include provision for mitigation in respect of forecasted NS Power savings enabled by the LRS's supply of electricity to its Retail the RtR Customers. The savings credits will be determined annually on the basis of experience and will be applied on a prospective basis.

4. The Energy Charge under this RTT includes provision for annual adjustment on a prospective basis to account for the forecasted difference between NS Power's average avoided cost by the LRS's supply of electricity and its average system fuel cost. If the average avoided cost exceeds the average system fuel cost, this adjustment will be a reduction in the Energy Charge; if the average avoided cost is less than the average system fuel cost, this adjustment will be an addition to the Energy Charge.

ENERGY CHARGE

Energy charge is made up of the following components:

Energy Charge Components	Cents per kWh
Fixed Cost Adder from Energy Balancing Service Tariff	3.451
Annually Adjusted Energy Savings Credit	-
Annual Energy Cost Adjustment	-
Total	3.451

The Energy Charge is applicable to the LRS's monthly displaced energy on NS Power's generation system, defined as the total monthly LRS load, including distribution losses, minus the total monthly LRS top-up quantity as determined under the Energy Balancing Service Tariff for that LRS.

DEMAND CHARGE

Demand Charge is made up of two components:

Demand Charge Components	Dollars per kW
Demand Charge from Standby Service Tariff	$5.370
Annually Adjusted Demand Savings Credit	$0.000
Total	$5.370

The Demand Charge is applicable to the LRS's monthly displaced demand on NS Power's system determined as the difference between Winter Peak Firm Demand, in respect of the monthly bill of the LRS, and Monthly Standby Contract Demand, both as determined under the Standby Service Tariff for that LRS. For greater certainty, Winter Peak Firm Demand and Monthly Standby Contract Demand are as set out in the Standby Service Tariff.

SPECIAL CONDITIONS

(1) Nothing contained in this RTT or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to unilaterally make application to the Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this RTT.

Nova Scotia Power

Renewable to Retail Project

RtR Design Basis Report

Robert Cary & Associates Inc.

28th August, 2015

Contents

1 Introduction

1.1 Design Basis Report

This report provides an overview of the proposed implementation of a Renewable-to-Retail (RtR) market framework in the Province of Nova Scotia. It includes discussion of options considered and the basis for selection of particular design elements. It also describes how this framework is implemented through specific tariffs and other instruments.

1.2 Role of Robert Cary & Associates Inc

Robert Cary & Associates Inc (RCAI) was engaged by Nova Scotia Power Inc (NS Power or Company) in September, 2014 to assist and make recommendations to the Company with respect to the development in Nova Scotia of the framework of the RtR market prescribed in the *Electricity Act (Nova Scotia)* as amended by the *Electricity Reform (2013) Act (Nova Scotia).*

Robert Cary has extensive experience in electricity market design, in commercial arrangements within electricity markets, and in the governance of electricity distribution utilities. Mr Cary's resume is attached as Appendix A to this report. In undertaking this assignment, Mr Cary has brought to bear his particular knowledge of the Nova Scotia electricity market as well as his experience in the integration of renewable low impact (principally wind) generation in the Ontario market. His Nova Scotia experience includes:

- Nova Scotia electricity market design (as implemented), including: independent review of the recommendations of the Nova Scotia Electricity Marketplace Governance Committee with respect to achievement of Energy Policy objectives, and to practicality; advice to NSPI on tariff design issues and market documentation; and drafting of market rules for the Nova Scotia electricity market for the Nova Scotia Department of Energy under the oversight of a steering committee including stakeholder representation.
- Nova Scotia renewable energy trading system design (not implemented), including: preparation of discussion papers to outline options for implementation of renewable electricity trading systems, followed by leadership of discussion forum, collation of stakeholder responses, and finalization of policy options as a basis for possible legislation and regulation; and assistance in determining terms of reference for a wind power integration study.

Following discussions with NS Power, RCAI prepared a report[1] and made a related presentation to stakeholders on October 9, 2014. The report and presentation set out four basic framework options to be considered in design of the RtR Market.

Following evolution of the design with regard to stakeholder comments, RCAI prepared a report[2] on Embedded Cost Recovery approaches, and made a related presentation to stakeholders on December 15, 2014. This report and presentation discussed options for embedded cost recovery, and provided the basis for the discussion on 15th December and subsequent stakeholder feedback.

On March 2, 2015, RCAI presented to stakeholders an update on the evolving basis of the RtR market design[3]. In addition to providing an update on certain decisions made to that date on the development of the more detailed design, this presentation identified certain of the outstanding issues remaining to be resolved.

Since the March meeting, RCAI has consulted with and advised NS Power with respect to the finalization of design of the RtR Market framework and of the various specific tariff instruments. RCAI has also participated in the preparation and review of the various RtR tariffs and related documents proposed by NS Power, including the following:

- Distribution Tariff
- LRS Terms and Conditions and Participation Agreement;
- Renewable to Retail Market Energy Balancing Service Tariff;
- Renewable to Retail Market Standby Service Tariff;
- Renewable to Retail Market Transition Tariff;
- Open Access Transmission Tariff; and
- Market Rule amendments.

This design basis report is therefore the work of RCAI. It includes discussion of the issues that were required to be addressed in key decisions made by NS Power and the basis for those decisions.

1.3 Overview of the RtR Market

The RtR market is to be established in accordance with the *Electricity Act (Nova Scotia)* as amended by the *Electricity Reform (2013) Act (Nova Scotia).*

[1] The Market Design White Paper dated 2nd October, 2014

[2] The Embedded Cost Recovery White Paper dated 2nd December, 2014

[3] The Renewable to Retail Project Design basis development presentation dated March 2015

The RtR supply chain will comprise:

- Generators of renewable low impact electricity located in Nova Scotia, as certified by the Nova Scotia Department of Energy;
- Retail Suppliers, who will be licenced and subject to regulation by the Nova Scotia Utility and Review Board (UARB or Board) for this purpose; and
- Retail electricity customers in Nova Scotia.

Retail Suppliers licenced by the Board are referred to throughout this report as Licenced Retail Suppliers, or “LRSs”. The functions of generators and of LRSs are distinct and they may be performed by separate entities or both functions may be performed by the same entity. They are described in this document as separate entities, but there is no requirement under the *Electricity Act* that they be separate.

Each certified generator will sell[4] its production to an LRS, which will utilise services procured from NS Power to deliver electricity to retail customers and to reconcile between the timing of generation and the timing of load. Those services are designed such that the reliability of electricity supply received by RtR customers is the same as that received by those same customers taking Bundled Service from NS Power. The proposed services to be provided by NS Power include physical delivery services as well as backup and balancing services.

The RtR framework proposed by NS Power is based on and assumes all RtR tariffs and associated cost recovery being applicable to all RtR based transactions, regardless of the location of the generator relative to the load.

The Nova Scotia Department of Energy’s processes for certification of generators and the UARB’s processes for licencing of LRSs, including the posting of associated Retailers Regulations and Code of Conduct, are expected to provide RtR consumer protection including, in particular, that each LRS must provide to the grid in each two-year compliance period sufficient renewable low impact electricity to fulfill the supply to its retail customers and the associated transmission and distribution losses.

1.4 Executive Summary of the Market Design as Proposed

The RtR Market design is embodied in a number of instruments:

- Each RtR generator is required to execute a Wholesale Market Participation Agreement by which it is bound by the relevant provisions of the Wholesale and RtR Market Rules and of the Open Access Transmission Tariff (OATT), and it is required to execute a Generator Interconnection Agreement. Collectively these provide for the generator to maintain acceptable

[4] To the extent that Generator and LRS are the same entity, there is no “sale”.

technical standards and to communicate with and accept direction from the Nova Scotia Power System Operator (NSPSO) while supplying electricity to the LRS to which it is contracted.

- Each LRS is required to execute an LRS Participation Agreement and a Wholesale Market Participation Agreement by which it is bound by the relevant provisions of the revised Market Rules and of the OATT, as well as the Standby Service tariff, the Energy Balancing Service tariff, and the RtR Transition Tariff. The terms and conditions attached to the LRS Participation Agreement govern such aspects as customer transfer arrangements, metering, settlement, security, and confidentiality.
- The design of the generation-related tariffs is intended to collectively provide for NS Power to backup the RtR supply to achieve equivalent reliability of supply, to accept from the LRS the excess RtR generation that may arise in any hour, and to recover from each LRS the embedded costs stranded by the LRS's activities. Generation-related tariffs are charged (or credited) to each LRS in respect of the aggregate load served by that LRS and the aggregate of generation supplied by that LRS. The proposed generation-related tariffs comprise:
    - The Standby Service tariff provides for the availability of the capacity necessary to ensure overall system adequacy in respect of the RtR load, and the availability of NS Power generation facilities to support hourly RtR customer load in excess of hourly RtR generation. The monthly charge is based on the costs of overall capacity required to serve the aggregated RtR customer load, less the capacity self-supplied by the LRS.
    - The Energy Balancing Services tariff provides for the actual operation of NS Power generation facilities for the top-up energy necessary to supply RtR customers in any hour when the RtR generation is unavailable or insufficient to meet that customer load, and it provides for NS Power to manage the operation of its generation facilities in any hour in order to receive surplus RtR generation above RtR customer load. The fuel component of the top-up charge and spill credit are proposed to be set prospectively on annual basis based on the forecasts of annual incremental costs of top-up energy and avoided costs of spill energy, respectively.
    - The RtR Transition Tariff provides for payments by the LRS to keep NS Power's remaining customers whole in respect of fixed generation costs not collected through the above tariffs and not otherwise capable of avoidance or mitigation.

  The specific charges under these three tariffs are all based on the Cost of Service analysis model used for consideration of Bundled Service rates, and are set so that they should together collect for NS Power the total generation cost excluding that allocated to the provision of OATT Ancillary Services, less the NS Power cost avoided due to the displacement of NS Power generation by RtR supply and any mitigation available to NS Power.

- The OATT provides for the delivery of the rebalanced generation supply (ie inclusive of top-up but exclusive of spill) to meet metered loads of any transmission-connected RtR customer or energy requirements adjusted to transmission level of distribution-connected RtR customers. It includes all ancillary services associated with such delivery. The OATT charges are unchanged from those currently in effect, with the exception of modification of the hourly imbalance service in schedule 4 to avoid double counting with the Energy Balancing Services tariff. OATT charges are charged to each LRS in respect of the aggregate load served by that LRS.

- Each distribution-connected RtR customer will maintain a relationship with NS Power through the proposed Distribution Tariff. NS Power will determine individual customer charges each month. NS Power will bill these to each LRS, and each LRS will bill and collect the distribution charges directly from RtR customers. Section 10 of the UARB's draft Code of Conduct requires that the bill amount under the NS Power Distribution Tariff be charged without markup to the LRS's customers. The charge rates in the Distribution Tariff correspond to the distribution and retail elements of the Bundled Service[5] Cost of Service analysis model.
- Any transmission connected RtR customer will not be subject to the proposed Distribution Tariff, but will maintain a customer relationship with NS Power through an operating agreement.

1.5 Conclusions and Opinion

This report describes the proposed RtR Market framework and the instruments to be used by NS Power for its implementation. It outlines the consultations with stakeholders. And it includes discussion of the issues that were required to be addressed in key decisions made by NS Power, and the basis for those decisions.

It is the opinion of RCAI that the proposed market framework as described herein:

- has been designed to meet the requirements of the *Electricity Act (Nova Scotia)* as amended by the *Electricity Reform (2013) Act (Nova Scotia);*
- has been designed with due regard to stakeholder inputs;
- represents a rational approach which utilises to an appropriate extent the existing tariff framework and the Cost of Service analysis behind the existing Bundled Service and other tariffs;
- will provide for transparent, fair, equitable and reasonably stable rates for services provided by NS Power to the RtR supply chain, and for the recovery of embedded costs associated with service to RtR customers that would otherwise be borne by remaining NS Power customers; and
- will be capable of evolution to meet changing requirements as the RtR market itself develops.

[5] See Section 2.2 of NS Power's application. Bundled Service refers to electrical service taken from NS Power under existing NS Power tariffs. This takes the form of having generation, transmission, distribution, ancillary services and all other items associated with the provision of such service blended or bundled within the rate.

2 RtR Participation Arrangements

2.1 LRS Participation Agreements

Each LRS will be required to execute an LRS Participation Agreement with NS Power. The proposed form of the LRS Participation Agreement is attached as Appendix B to the LRS Terms and Conditions, and will bind the LRS and NS Power to the LRS Terms and Conditions. As proposed, these terms and conditions include the obligation on the LRS to subscribe to all of the LRS Tariffed Services comprising:

- RtR Market Standby Service Tariff, which provides for NS Power to provide capacity required to fulfill its obligations in respect of overall system adequacy and in order to provide energy top-up;
- RtR Market Energy Balancing Service (EBS) Tariff, which provides for NS Power to provide energy top-up and accept energy spill due to mismatch of an LRS's generation and its load;
- RtR Market Transition Tariff (RTT), which provides for embedded cost recovery in respect of generation; and
- OATT, which provides for transmission and ancillary services.

The LRS Participation Agreement and the associated LRS Terms and Conditions will also establish the framework for customer service transfers and for access to metering data.

In addition, each LRS will execute a Wholesale and RtR Market Participation Agreement by which the LRS will become a Market Participant and will be bound by the Market Rules.

An RtR generator that is not also an LRS will be required to execute a Wholesale and RtR Market Participant Agreement by which it will become a Market Participant and will be bound by the Market Rules.

2.2 Alternative Options Considered

2.2.1 Selected Option; LRS Participation Agreement

The selected option of the LRS Participation Agreement has the benefit of clarity. It has been drafted specifically for this purpose and has embedded all necessary provisions in a single document. It creates a clear contractual relationship between each LRS and NS Power. It can allow for unified administration and settlement of all the various tariffs and payment security provisions.

2.2.2 Rejected Option; Modified WMP Agreement and Market Rules

Consideration was given to an alternative option based on the Market Rules. Under this option, the Wholesale Market Participation (WMP) Agreement and the Wholesale Market Rules and Market Procedures would have been modified and expanded to specify all the terms and conditions necessary to govern the relationship between NS Power and the LRS and the obligations of each.

This alternative was rejected for two reasons:

- The purpose of the Market Rules is to define the rights and obligations of the NSPSO towards Market Participants, and of Market Participants towards the NSPSO. The RtR Participation arrangements relate to the rights and obligations of NS Power and the LRS towards each other.
- The addition to the WMP Agreement and Wholesale Market Rules of all the necessary obligations would be irrelevant to Wholesale Market Participants, and cause potential confusion.

The Market Rule amendments required under the selected option are relatively minor.

2.2.3 Rejected option; Obligation though UARB licence

A further option proposed during the stakeholder consultations was that the granting of a licence by the UARB to an LRS should create a deemed contract between the LRS and NS Power. The proposal was considered by NS Power and not selected for the following reasons:

- Absent a deemed form of contract, the terms could be ambiguous, and once the deemed form of contract is established, the deeming process offers no benefits;
- It would be unclear how deemed contract provisions could be enforceable between the deemed parties other than through the UARB itself;
- It would be unclear how such deemed provisions could survive licence termination; and
- The UARB would become potentially involved in the commercial relationships over which it has regulatory oversight, thus creating a conflict with the regulatory role of the UARB.

2.3 Customer Relationship with NS Power

As noted below, customers connected at distribution voltage will become distribution customers. The request to switch to RtR service will trigger a change from being a Bundled Service customer to distribution access customer. The retail customer will be an NS Power distribution customer notwithstanding billing arrangement through the LRS. NS Power has proposed amendments to its standard Regulations to provide for this.

Customers connected at transmission voltage level are not distribution customers. It is intended that they maintain a customer relationship direct with NS Power through an individual operating agreement that will set out the mutual obligations of the parties. This will not, however, provide for payments direct between the customer and NS Power.

3 Customer-facing design

3.1 Billing and Collection: High Level

NS Power identified options for NS Power consolidated billing, split billing, and LRS consolidated billing. Stakeholders' feedback indicated a preference for LRS consolidated billing[6]. As a result, the RtR design framework has been developed on the basis of LRS consolidated billing. LRS Tariffs provide for the provision of all RtR Tariffed Services to the LRS, in the expectation that the LRS will incorporate recovery of the costs for these services into its rates to its customers. The Distribution Tariff will establish a direct relationship between NS Power and RtR electricity consumers / customers, but will provide for the LRS to effect LRS-consolidated billing. NS Power will bill to, and receive payment in full from, each LRS in respect of services provided to its customers in respect of Distribution Tariff charges. Detail is developed in section 3.7 below.

3.2 Service Duration

NS Power's Bundled Service tariffs are designed to provide appropriate cost recovery over each calendar year, subject to certain specific deferred cost recovery provisions. RtR tariffs are all designed on the same basis with an assumption that customers would switch to RtR service for contract periods not less than a year. In the event that NS Power notes significant incidence of more frequent switching, NS Power should consider the addition of controls that would identify and preclude more frequent switching except following approval in response to special and unplanned changes of circumstance.

3.3 Interruptible Service

Interruptible service has been made available by NS Power as a Bundled Service option to qualifying large industrial customers. Those customers undertake to interrupt their load on demand (or by remote trigger) of the NSPSO. Failure to implement such interruption triggers a penalty up to twice their monthly bill (at the applicable bundled firm service rates).

NS Power relies on the fact that such interruptible customers do not contribute to the firm load on the system, and therefore are not included in the determination of the firm dependable capacity requirement of the system. The notice provisions for switching back to firm service reflect the time that would be required for NS Power to develop additional firm dependable capacity to fulfill the increased system adequacy requirement.

In discussion with stakeholders, it was indicated that any switch between Bundled Service and RtR service would take place without changing the interruptibility of the customer. The exercise of that

[6] As noted in RCAI presentation on design basis development, March 2015, slide 6.

interruptibility would be independent of bundled / RtR status, and would be independent of whether RtR generation was operating at that time. The possible carry-over of existing facility interruptible status would require a number of issues to be resolved:

- Interruption communications would need to be to the load customer, who would continue to be NS Power's distribution customer or RtR Customer Network Operating Agreement customer;
- Contractual arrangements would have to be executed reflecting *inter alia* the two part penalty arrangements comprising Threshold and Performance components as in effect for the bundled service.;
- The proposed Standby Service Tariff and RTT would both require further amendment to include provisions to reflect interruptibility; and
- NS Power would expect that the LRS and RtR customer would negotiate for the RtR customer to receive the benefit of the reductions due in the Standby Service Tariff and RTT.

Given the small number of interruptible service customers and the uncertainty of any demand for interruptible RtR service, NS Power has not at this time provided systems or tariffs for interruptible RtR service. Should any interruptible customer seek RtR service, NS Power would have to review the specific additional requirements noted above and determine how these can be achieved. If satisfactory solutions are identified, these could be addressed through revisions to proposed tariffs and LRS Participation Agreement, and, for a transmission-connected customer (which class represents most of the existing interruptible customer load), the terms of the required operating agreement.

3.4 Full / partial service

Some stakeholders provided design feedback indicating a preference that large customers should have the option to take partial RtR service from NS Power. This was understood by the Company to mean that a portion of the metered customer load should be considered as RtR load, and the balance as Bundled Service load. This concept of partial service is distinct from the discussion of Behind-the-Meter service, which is discussed section 3.5 below.

Parial service could take two forms: unrestricted partial service; and restricted partial service. In unrestricted partial service, the LRS or customer would be able to vary the split between Bundled Service and RtR service. In restricted partial service the customer's hourly load would be split between NS Power Bundled Service and RtR service in a predetermined ratio which would be fixed for a year at a time.

Unrestricted partial service was excluded early in the RtR Market design. The Cost of Service approach to Bundled Service rates and to the various RtR tariff rates is based on the broad characteristics of each class load shape. Unrestricted partial service would distort the load shape of each part of the service when considered separately, and may result in significant distortion of rate impacts, and thus in cost transfer to remaining customers. In order to allow unrestricted partial service while avoiding such cost transfer, the Bundled Service rates could need extensive revision to incorporate time-of-use and seasonal variability. Costs of such revision would need to be borne by the applicant for such type of service. And such development would depart from the requirement to leverage existing tariffs to the extent possible. Unrestricted partial service was therefore excluded from consideration.

Consideration was then given to enabling large customers to elect a restricted partial RtR service in the form of an annually fixed percentage of metered hourly load. This arrangement would preserve Bundled Service load shape, at lower scale. This was discussed with stakeholders as a design element under consideration. Stakeholders provided no comment on this possible design element. No precedents could be identified for this type of arrangement at the retail level. Implementing such an arrangement would introduce added complexity to settlements. In view of these considerations, NS Power did not include partial service provisions in the design framework.

It should be noted that the full service model (either RtR or Bundled Service) applies separately to each customer account. If a customer has multiple accounts, each account being separately metered and separately identified in billing, the customer may elect RtR service for some such accounts but not for others. Such treatment is permitted and is not considered as partial service.

3.5 Behind-the-Meter RtR supply

During the stakeholder consultations, it was suggested by a stakeholder that the RtR framework should accommodate a model which would permit a LRS to connect a renewable low impact generator directly to a number of customers, apparently behind a single NS Power meter that would measure the net energy withdrawn from the system at that point. Each customer would thus be served by a micro-grid behind that single NS Power meter. It seems to be implicit in this proposal that NS Power would render charges under its Bundled Service tariff to the group customer on the basis of those net energy flows at the interface between the NS Power grid and the LRS microgrid.

In an alternative arrangement, an LRS could install individual generation units at each of its customers' premises, and serve each customer behind its NS Power meter.

The cost impact on NS Power of either behind-the-meter (B-t-M) arrangement is exactly the same as the underlying cost impact of connecting the generation on the system side of any metering. What changes under either of these B-t-M arrangements is the extent of NS Power's recovery of its costs under its Bundled Service and proposed RtR tariffs. The proposed business model would, absent secondary metering or special adjustments discussed below, result in a shift of the cost burden from that nexus of B-t-M generator, the LRS and its customers to NS Power and its remaining Bundled Service customers. This would be inconsistent with the "no-harm" provisions of the *Electricity Act*, which provide that the remaining customers of NS Power are not to be negatively affected by the introduction of the RtR market and that the LRS and its customers are to be responsible for all costs relating to the provision of service by the LRS that would otherwise be the responsibility of NS Power.

The cost transfers referred to above would arise in a number of ways. Under a B-t-M arrangement, NS Power and its remaining customers would be exposed to transfer of embedded costs:

- In either configuration:
  - the amount corresponding to the RtR distribution charge on the B-t-M generation quantity;
  - the amount corresponding to the OATT charges on the B-t-M generation quantity;
  - the amount corresponding to the 20% generation reserve margin portion of the B-t-M generation;
  - the amount corresponding to the RtR Market Transition Tariff (for embedded cost recovery) on the B-t-M generation quantity; and
  - a possible amount arising from any change in the residual customer load shape from the original customer load shape.
- And in the micro-grid configuration:
  - customer monthly charges on all but one customer; and
  - an amount that could arise from consolidation of customer load shape (whereby the diversity is lost to NS Power) and possibly from the customer class of the aggregate being different from the customer classes of the individual end use customers.

The Retailers Regulations issued July 15, 2015, contemplate B-t-M to be a form of RtR supply. The LRS would thus be required to execute an LRS Participation Agreement and be subject to all RtR tariffs, and not to any Bundled Service tariff. There are two ways to accommodate the no-harm requirement within the RtR tariff framework, namely: secondary metering; and enhanced recovery of embedded costs. These are described as follows:

- Secondary metering:
  - Secondary metering would be installed at individual customer premises and would be used as the basis for determining charges under all RtR tariffs including charges to the LRS in respect of distribution access[7].
  - Secondary metering is probably required by the LRS to measure its sales to its customers; NS Power would require that such secondary metering be capable of hourly recording and remote polling by NS Power.
  - In the case of a single customer B-t-M arrangement, the secondary meter could be a virtual meter for which the readings are derived by the summation of the primary NS Power meter and the meter that would record generator production.

[7] The last leg of the end use customer connection is the micro-grid owned by the LRS, so that end use customer would not be an NS Power customer and would not have a direct customer relationship with NS Power. The LRS would be the distribution customer at the interconnection of the micro-grid to the NS Power system. In order to avoid stranding of embedded distribution system costs, the LRS Participation Agreement would provide that the settlement of the Distribuition Tariff (*inter alia*) be based on the secondary metering at end use customer delivery points.

- Enhanced recovery of embedded costs:
    - As noted above, without secondary metering for use in RtR tariff settlement, a B-t-M arrangement would strand certain costs. In order to avoid transfer of those costs to remaining NS Power customers, those costs need to be recovered from the particular LRS serving RtR customers by a B-t-M arrangement.
    - The most appropriate way to do this would be by a special B-t-M Transition Tariff or equivalent. This would aggregate all of the foregone amounts noted above. The accurate way to do this would be by the use of secondary metering. Absent secondary metering, NS Power would have to estimate the foregone amounts for payment by the B-t-M LRS.

The secondary metering option provides the simpler solution. It utilises the already proposed RtR tariffs, avoids stranding additional costs, and therefore avoids the potentially onerous need to create a special B-t-M Transition Tariff.

NS Power has therefore adopted the secondary metering approach.

3.6 Meter Ownership and Related Issues

In accordance with NS Power's initial proposal, which was generally supported by stakeholders[8], NS Power will continue to own and to read the meters. In requesting RtR service, RtR customers would authorise NS Power to provide metering and relevant billing data to the LRS.

The settlement for balancing and other services provided by NS Power to each LRS requires determination of hourly generation and load quantities. Generation facilities will normally have metering capable of providing such hourly production data. Domestic and other smaller bundled service customer class metering requirements currently only provide cumulative energy consumption quantities over each (typically 2 month) meter reading cycle. They do not provide hourly data.

NS Power noted stakeholder support for its proposal to minimise the cost of implementation by utilising the existing cumulative energy metering, and creating inferred hourly consumption quantities by utilising research-based class load profile data. On further consideration NS Power concluded that:

- While there is an initial cost saving in the use of existing cumulative energy meters, there is also an administative cost increase in the inference of hourly consumption data. The task is complex due to the need to consolidate inferred data from customers each of whom may have different meter reading cycles.

[8] One stakeholder requested the option of LRS meter ownership for purposes of installing hourly interval meters. In the context of NS Power's present plans to utilise interval meters for all RtR service, this option is now redundant.

- The use of inferred data adds two months to the settlement cycle for the relevant NS Power services to each LRS.
- Existing infrastructure for remote polling of interval meters has capacity to accommodate at least the initial uptake by RtR customers.

NS Power therefore considers that it is more effective to move directly to remote polled interval metering as a requirement for all RtR customers at commencement of the RtR market. Meters would be upgraded following receipt by NS Power of an RtR service request for customers requiring such meter upgrades.

The hourly class standard load profile for any customers in unmetered classes will be as used to infer hourly load profiles for any RtR customers in such classes.

3.7 Billing and Collection

Billing and collection arrangements between each LRS and its customers are matters for consideration in the Retailers Regulations and Code of Conduct, and are not part of this design basis document.

Billing and collection arrangements between NS Power and each LRS should be considered in three tranches:

- Customer-specific billings to the LRS or customers;
- Aggregate billings to the LRS; and
- Fuel Adjustment Mechanism, DSM cost recovery, and miscellaneous charges.

3.7.1 Customer-specific Billings to the LRS or Customers

For service under the Distribution Tariff, NS Power will invoice the LRS monthly for each individual customer charge.

3.7.2 Aggregated Billings to the LRS

The following tariffs will use charge determinants that reflect the aggregate of all RtR customer loads:

- Transmission service under the OATT, including:
  - Network service under schedule 10;
  - Ancillary services under schedules 1, 2, 3, 5, and 6;
  - New schedule 4A in place of existing schedule 4, all as discussed in section 5.3.2; and
  - Self-supply of transmission losses in accordance with schedule 9, using renewable low impact electricity generated in Nova Scotia.
- Standby Service;

- Energy Balancing Service, comprising:
    - Top-up service;
    - Spill, including at a discounted rate for the annual excess of spill over top-up beyond a certain percentage of total RtR customer load;
- RtR Market Transition Tariff in respect of embedded cost recovery.

Having adopted remote polled interval metering for all RtR customers, NS Power will be able to bill the LRS for all these services following each calendar month end.

3.7.3 Fuel Adjustment Mechanism (FAM), DSM Cost Recovery, and Miscellaneous Charges

The FAM tariff includes a provision that outstanding FAM balances in respect of customers migrating to non-FAM be charged to those customers. NS Power will therefore charge or credit any outstanding FAM balances to those customers in accordance with the FAM. No special provision is required in the RtR tariffs to accommodate this process.

The means of recovery in respect of all DSM costs remains to be determined. It is expected that DSM cost recovery will apply to Bundled Service customers and to RtR customers alike, or possibly in the case of RtR customers to their LRS. NS Power would be able to charge all customers in accordance with that DSM cost recovery mechanism as an element embedded into the Cost of Service analysis used in the determination of Bundled Service and RtR tariff charges. No special provision would be required in the RtR tariffs to accommodate this.

Costs of interval meter installation and other miscellaneous charges will be recovered at cost in accordance with NS Power Regulation 7.1[9]. The interval metering charges will be billed to the LRS, as the interval metering is necessary for aggregation of the LRS's customer load, and not necessary for determination of Distribution Tariff charges which could be billed using a standard cumulative energy meter.

4 Tariff Design: General

4.1 Disaggregated Tariff Approach

RCAI's October, 2014 Market Design White Paper identified a range of RtR design options to stakeholders, and sought stakeholder feedback.

[9] Approved NS Power Rates and Regulations can be found at http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/rates/default.aspx

The financial market option as presented would have left NS Power Bundled Service tariffs in place for all customers. Under this model, NS Power would have credited each LRS with NS Power's costs avoided by virtue of the RtR generation, and the LRS would have in effect billed its customers for the cost of the renewable attributes associated with its supply. This framework would have the simplest implementation and lowest administrative costs, however it did not satisfy stakeholder preferences for a more physically defined RtR "product".

The remaining alternatives were described as a disaggregated tariff approach, an avoided cost approach, and a hybrid between these two. Notwithstanding its higher complexity, there was clear stakeholder preference for the disaggregated tariff approach. While the total amounts to be recovered by NS Power under each option are the same, stakeholders preferred the greater transparency associated with the disaggregated tariff approach. As a result, NS Power has adopted the disaggregated approach in the design of its various RtR tariffs. While the tariffs are disaggregated into their individual elements, they are designed to operate as a suite of interrelated tariffs that collectively provide for the appropriate levels of service and cost recovery. The design does not contemplate an LRS being able to select some but not others. Execution of the LRS Participation Agreement would bind an LRS as a customer under all of the RtR tariffs.

The tariffs fall into two categories:

- The Distribution Tariff, under which each individual customer meter reading is used as a charge determinant; and
- LRS tariffs, under which the charge determinant is an aggregate for each LRS derived from many different customers and in many cases generator characteristics or meter readings.

In its development of the disaggregated tariff approach, NS Power gave careful consideration to the applicability of the existing OATT to the RtR Market. With the exception of schedule 4, it was concluded that the existing wholesale market OATT is generally appropriate for application in the RtR market. Schedule 4 is replaced by schedule 4A for RtR Market Participants, as discussed in section 5.3.2 below.

4.2 Avoiding Negative Impacts on Other Customers

The tariff design was strongly driven by the *Electricity Act* requirement that other remaining customers of NS Power are not to be negatively affected if some retail customers choose to purchase renewable low impact electricity from an LRS.

The avoidance of negative impacts on other customers is achieved in the disaggregated tariff approach by the use of the same Cost of Service model and cost allocation approach as is used to support Bundled Service rate setting. Costs are allocated for recovery from the RtR supply chain on a forward-looking basis compatible with the Bundled Service approach. The proposed RtR tariffs have been designed to ensure that NS Power should bear the same aggregate risk of actual outcomes in respect of RtR load as it does for Bundled Service load.

RtR rates are therefore expected to be adjusted, if required, in parallel with Bundled Service rates, including where applicable in parallel with the annually adjusted rate processes.

4.3 Rates and Expense Recovery

As noted in the 2014 Cost-of-Service analysis[10], the revenue recovery per retail rate class varies from 4.4% below allocated expense for the Large Industrial class to 4.4% above allocated expense for the Small General class. The Residential class rates recover 0.9% below allocated expense. These differences are small. They arise from historical rate development and a policy of continuity, as opposed to any present policy purpose that should be carried forward into RtR rate setting.

Recovery ratios are determined at the level of the Bundled Service aggregate per customer class. The only RtR tariff based on customer classes is the Distribution Tariff, and the recovery factors are not necessarily valid for this specific tariff in isolation. Bundled Service recovery ratios are therefore not carried forward into RtR rate determination. The Distribution Tariff rates are in effect set for recovery ratios of 1.00 for every class.

5 Tariff Design Specifics: Supply Elements

5.1 Context

The supply-related cost represents the largest component of the existing cost of Bundled Service, as it includes the asset-related cost (including financing and return on equity) of all generating plant, the fixed and variable O,M & G associated with that plant, and the fuel cost including electricity purchased under Power Purchase Agreements and as imports, net of any export sales revenues.

If NS Power and its remaining customers are to avoid economic disadvantage from the implementation of the RtR market, then the total amount to be recovered by NS Power under the set of supply related tariffs and ECR payments should equal the total that would have been recovered from RtR customers if they had remained Bundled Service customers, less the costs that NS Power can avoid by virtue of the RtR generation supply to the grid. The total amount to be recovered by NS Power under the set of supply related RtR tariffs and ECR payments will be collected through the combination of:

- Energy Balancing Service (EBS), comprising top-up revenue net of spill credits;
- Standby Service tariff revenue; and
- RtR Market Transition Tariff revenue for embedded cost recovery.

[10] NS Power compliance filing; Appendix 1 – COSS compliance model, electronic format, tab “Exh 1”.

To the extent that NS Power recovers fixed costs through the EBS tariff (top-up net of spill) and the Standby Service tariff, NS Power fixed costs to be recovered though the RtR Market Transition Tariff are lower. To the extent that cost recovery though other tariffs might be reduced, those costs to be recovered though the RtR Market Transition Tariff would increase.

Fuel Adjustment Mechanism amounts and potential DSM cost recovery are separately addressed within section 3.7.3 above.

The proposed RtR Market EBS and Standby Service tariffs were developed with due consideration of the tariffs presently in use by Wholesale Market Customers. The RtR Market tariffs were designed for application in the RtR Market context and do not replace those Wholesale Market Tariffs applicable to Wholesale Market customers.

5.2 Cost Allocation Principles

The Energy Balancing Service, Standby Service, and RtR Market Transition tariffs have been designed to incorporate the same fixed cost classification and allocation principles as in the Cost of Service analysis used in the determination of Bundled Service rates.

In the context of Bundled Service Cost of Service analysis:

- The fixed generation costs comprise fixed asset amortization, financing and returns on equity, as well as associate operating maintenance and general (OM&G) costs, and exclude those costs classified as fuel;
- These fixed generation costs are classified (in two stages) into those recoverable against demand and those recoverable against energy; and
- These costs are then allocated to rate classes according to the rate class contributions to system demand and to energy use.

The first two steps are used in the context of RtR rate setting. There is no explicit allocation by RtR customer rate class, as the relevant RtR tariffs are all settled on an aggregated basis. Instead, the rates used in those tariffs are based on the system-wide unit averages for costs recoverable against each of demand and energy. In aggregate therefore, the costs borne by LRS (and thus indirectly by RtR customers) are the LRS's properly allocated share of the system-wide fixed generation costs.

5.3 Energy Balancing Services (top-up and spill); Design Principles

Top-up and spill services are addressed together under the proposed EBS tariff. As both are energy-based charges, the rate determination of each shares common elements, and settlement of each also shares common elements.

5.3.1 Purpose

The purposes of the top-up and spill services are essentially the time-shifting of the RtR generation supply so that it will match the needs of the RtR load. Each LRS will effectively use the NS Power system as an energy storage system, injecting surplus energy in some hours, and withdrawing to supply excess load in others.

The purpose of the top-up and spill tariff arrangement is to provide compensation to NS Power for the incremental costs of providing top-up when needed, and to the LRS for NS Power's incremental savings from spill. The top-up tariff also provides for recovery of the fixed generation costs classified as energy-related in the CoS model.

5.3.2 Interaction with Imbalance Tariff

OATT Schedule 4 services cover the differences in the Wholesale Market between the scheduled and the actual supply-demand balance (for single point services) or between scheduled and actual quantities separately for each of multiple supply and load points. LRSs are generally expected to serve load located behind multiple transmission delivery points using generation at one or more transmission receipt points, and, as such would (under existing Schedule 4) be subject to separate imbalance charges in respect of each transmission receipt and delivery point.

Careful consideration was therefore given to the interaction of top-up and spill tariffs with the OATT Schedule 4 imbalance tariff. Two options were considered:

- Under option 1, the OATT Schedule 4 would apply without modification. In order to avoid double counting of deviations, the top-up and spill tariff would need to be applied to the differences forecast in any hour between supply and load, while Schedule 4 would be applied to differences between forecast and actual at each receipt or delivery point, irrespective of offsets.
- Under option 2, the top-up and spill service quantities would simply be determined in each hour as the difference between actual supply and load in that hour, irrespective of forecast accuracy. This would exclude consideration of discrepancies between LRS's forecasts and actual outcomes and would naturally provide for offsetting deviations for each LRS within each hour. In order to recognise the additional costs that may arise due to inaccurate forecasts, a forecast discrepancy schedule is proposed as OATT Schedule 4A, to replace Schedule 4 for application in the RtR Market.

Careful consideration was given to the relative costs & benefits, incentives, consistency, and complexity of each of these two options.

Under either option, the variability within each hour is accommodated by the services provided under OATT schedule 3, so does not require to be addressed separately.

- Costs & benefits of each option:
  - The NSPSO is understood to manage its generation fleet and the transmission system using forecasts of load at each transmission delivery point, and forecasts of generation injection by each generator.
  - Processes that add to the accuracy of transmission delivery point forecasts are beneficial, but forecasts below this level may be onerous and add little or no value (depending somewhat on the source of the delivery point forecasts used).
  - The production of generation forecasts is relatively low cost and is an essential contributor to system management.
- Incentives:
  - Under option 1, the imbalance top-up rate under schedule 4 represents the incremental NS Power generation cost only, excluding the recovery of fixed generation costs allocated to energy. An LRS could gain by over-forecasting its supply and / or under-forecasting its load. This would reduce the energy quantity to be provided under the top-up tariff (which includes the fixed cost recovery element) and increase the energy quantity to be provided under the imbalance tariff (which does not include the fixed cost recovery element). This would be a perverse and counter-productive economic incentive to overstate generation forecasts or understate load forecasts.
  - Option 2 is designed to avoid the economic incentive arising under Option 1. There is no incentive to bias forecasts up or down, as the top-up and spill quantities are independent of the forecast. There is an incentive to forecast accurately the generation production in order to minimise costs under Schedule 4A.
- Consistency
  - Except under conditions of transmission constraint (to which OATT section 33 applies), any over-forecasts in one delivery zone and under-forecasts in others would naturally offset each other in system management. The existing OATT schedule 4, as applicable to dispersed load, would however result in net charges to the OATT customer that would not recognise those offsets.
  - Option 2 would not result in such inconsistency, as the generation forecast and actual are compared on an aggregate basis per LRS, and the load forercast is not required.
- Complexity
  - Option 1 requires the use of separate supply and delivery point load calculations for OATT schedule 4 settlement, as well as aggregate supply and load forecast calculations for top-up and spill calculations.
  - Option 2 uses metering results in aggregate to determine top-up and spill, and uses generation forecast and metered production data for settlement of OATT schedule 4A.

While option 2 foregoes the potential benefit of delivery point load forecasts, these forecasts would be onerous to produce and of questionable value.

The option 2 gains in simplicity, consistency, and incentive structure strongly outweigh that loss. NS Power has therefore proceeded with option 2.

5.3.3 Self-supply of Top-up

Consideration has been given to the potential for an LRS to self-supply top-up service from a generator other than its normal supplier(s) of renewable low impact electricity, as is permitted under the OATT. Three scenarios were considered:

- A renewable low impact generator in Nova Scotia could theoretically be available to provide occasional top-up energy: such a generator would have to be operating on a merchant basis (so as to be available as needed) but without any in-Province sink for its energy at other times. This is therefore an impractical scenario and is not recognised in the proposed EBS tariff.
- A non-renewable generator, such as a natural gas or diesel engine, could provide standby and top-up as required, but the top-up would not contribute to fulfilling an LRS's compliance requirement. Any such production would add to the net annual excess spill by that LRS. Such a generator would also have to be operating on a merchant basis, and also without any in-Province sink for its energy at other times. This is also an impractical scenario and is not recognised in the proposed EBS tariff.
- A third option would be energy imported for the purpose of top-up. Any such import would be scheduled in advance, tagged in such a way as to identify it as top-up, and therefore capable of inclusion in the top-up and spill settlement calculations. The imported energy could not qualify as renewable low impact electricity generated in Nova Scotia. It would reduce NS Power's fixed cost recovery under the EBS tariff, and therefore increase the amount to be recovered through the RTT. As a result, for the near-term, this approach would not be a viable option for the RtR market and it is not considered necessary to include the added complexity in the tariffs and processes to support this.

5.4 Energy Balancing Services; Charge Determinant

Top-up and spill quantities will have to be determined for each LRS for each hour, and will not be subject to net-off of quantities from hour to hour. The determination of top-up and spill quantities in each hour will be a joint retrospective calculation, for a month at a time.

It is proposed that the following steps be built into the process to determine the aggregate for an LRS of the hourly top-up and spill quantities in any month:

- Hourly customer meter readings will be aggregated by customer class, and then subject to class distribution energy loss adjustment to arrive at the class aggregate hourly load at transmission delivery points for each LRS.

- Class aggregate hourly load at transmission delivery points will be further aggregated to determine the system aggregate hourly load across transmission delivery points for each LRS.
- Hourly generator meter readings will be aggregated for each LRS, and will be reduced by transmission losses to determine the aggregate supply across all transmission delivery points for each LRS.

The LRS's aggregate hourly load at transmission delivery points is deducted from the LRS's aggregate supply at transmission delivery points in order to arrive at net hourly spill (positive results) and net hourly top-up (negative results).

5.5 Energy Balancing Services; Rates

5.5.1 Overview

The structure of top-up and spill services is driven largely by the cost allocation process summarised in section 5.2 above. On the basis of that discussion the proposed EBS tariff comprises:

- Top-up incremental cost charge per MWh of top-up in each hour;
- Spill incremental cost credit per MWh of spill in each hour, subject to discount in respect of annual excess spill; and
- Top-up energy allocated fixed cost rate per MWh of top-up in each hour.

5.5.2 Incremental Cost Element of Top-up and Spill Charges

The incremental costs of top-up and the avoided costs for spill vary according to the demand-supply balance on the system, and the type of generation that will be capable and most efficient to increment up or down. Two modes of systematic variability have been considered in design of the EBS tariff:

a) Load patterns: there are certain underlying seasonal load patterns and daily load patterns. Absent any variability of generation, these patterns would tend to require top-up to occur at times of high load (with higher marginal cost), and spill to occur at times of low load (with lower marginal cost).

   Load patterns could be accommodated into the tariff in two ways:

   - As time based rates recognising predictable load patterns, or
   - By incorporating a spread between top-up and spill to recognise the typical impact of systematic time differences.

b) Generation patterns: if the production pattern of variable RtR generation is correlated with other variable generation, then top-up requirements will occur systematically when other variable generation production is low and marginal cost is high, and spill will occur systematically when other variable generation production is high and system marginal cost is low.

Given the unpredictable nature of variable generation, it is not practical to use time-based rates to accommodate the generation pattern variation into rates. The only opportunity to do so is by using a spread between the top-up rate and the spill rate.

Other, non-systematic, variability will occur but should not create systematic differences in incremental cost that need to be reflected in the tariff. Should any such changes be identified at a later time, they could then be subsequently incorporated into a EBS Tariff revision.

It would therefore be possible in theory to adopt:

- Time based rates common to all technologies, with an additional spread superimposed according to generation technology (but this would be challenging to administer if an LRS has a portfolio of different supply technologies), or
- A spread applicable to all technologies, but likely to be applied to higher quantities of top-up and of spill arising with highly variable generation.

In order to avoid undue complexity, it is proposed that the incremental cost element of the rates will not have any seasonal or daily variation, but will reflect a mid-point rate and a spread. The mid-point rate will reflect the average avoided cost per MWh of incremental production weighted according to the hourly demand pattern over a year (which would represent a perfect match of RtR generation to average customer load shape). The spread will be set at a level to recover the reduction in overall avoided cost as the generation pattern departs from that ideal match and creates a need for annually balanced top-up and spill.

5.5.3 Allocated Cost Element

In order to recover the appropriate allocation of fixed generation costs to the production for top-up, the selected tariff structure adds the fixed generation cost allocated to energy to the incremental top-up rate. This is the same as the energy-based charge for fixed generation costs included in the Bundled Service Cost of Service analysis.

5.5.4 Annual Excess Spill Discount

The top-up and spill incremental rates discussed above are designed to recover the costs of providing annually balanced top-up and spill services. Any sustained bias towards top-up service quantity would represent an infringement of the LRS's compliance obligation as set out in the UARB draft Retailers Regulations, and would trigger a refund by the LRS to its customers. As such, it does not require separate tariff consideration. There can, however, be a sustained bias towards spill service, such as during periods when generation investment is ahead of customer recruitment.

This bias will tend to reduce further the costs avoided by NS Power due to spill. The rate payable to the LRS for such extra spill should therefore be discounted from the rate applicable to balanced spill.

5.6 Standby Service Tariff; Design Principles

Standby Service fulfills two functions:

- It provides to each LRS any firm dependable capacity required (in excess of the LRS's self-supplied firm dependable capacity) to support the share of total system adequacy requirement attributable to the LRS's load.
- It provides to each LRS the demand-based element of capacity required to provide top-up service.

If the combined generation fleet of NS Power and the LRSs is adequate to fulfill the firm dependable capacity requirement, then there should be adequate generation in Nova Scotia to meet the system energy requirement at all times, including in respect of each LRS's firm service customers, and during LRS generation outages. The charge determinant for this tariff is therefore based on the need to fulfill the firm dependable capacity requirement.

Given that RtR customers are to be served with the same reliability as equivalent Bundled Service customers, the system adequacy requirement is mandatory in respect of those customers. As a result, the Standby Tariff is a mandatory obligation for the LRS. This is in contrast to the voluntary backup service available to Wholesale Market customers under NS Power's existing Backup & Top-up Service tariff. In that Wholesale Market context, NS Power's obligation with respect to backup is limited to the contract demand.

5.7 Standby Service; Charge Determinant Principles

5.7.1 Concern with Existing Backup Service Charge Determinant

The demand charge portion of NS Power's present Wholesale Market Backup and Top-up Service tariff was reviewed for its applicability in the RtR Market. Based on NS Power's NPCC obligations to maintain system adequacy, the firm dependable capacity required to be available to the system before specific outages but discounted for dependability should be determined as follows:

1.20 x annual system coincident peak firm demand including associated losses

The LRS responsibility should therefore be determined as follows:

1.20 x LRS demand (including associated losses) at time of annual system coincident peak

An LRS will naturally self-supply some quantity of firm dependable capacity through its owned or contracted generation that is connected to the system under Network Resource Integration Service. Self-supply of additional generation capacity from other Nova Scotia resources is not practical for the same reasons as for Top-up service, as described in section 5.3.3. Self-supply of capacity from imports is equally impractical.

The quantity of capacity that must be purchased by any LRS from NS Power should therefore be determined as follows:

> *1.20 x LRS demand at time of annual system coincident peak minus the LRS's firm dependable capacity resources made available to the system under Network Resource Integration Service.*

For comparison, the demand determinant of NS Power's Wholesale Market Backup / Top-up Service tariff, interpreted to substitute the LRS peak monthly demand for the contract demand (CD) would give a billing demand under the present tariff of, and assuming that the LRS peak monthly demand exceeds average generation:

> *Billing demand = (20% x average generation) + (LRS peak monthly demand – average generation)*

Or if average generation exceeds LPD:

> *Billing demand = 20% x LPD*

This calculation will generally understate the requirement set out above to cover the costs of system needs. As such, it is appropriate for the RtR Standby Service tariff to utilise a different charge determinant that fully reflects the required contribution to system needs. This is developed in the immediately following section.

5.7.2 Charge Determinant Details

It is expected that customers can and will migrate between bundled service and RtR supply, and among LRSs, at any time of year. This presents a challenge in properly allocating costs for recovery from each LRS. The basis for cost allocation between classes , and for actual charges of large industrial customers uses winter peak demands. But the historical peak demands of an LRS in December, January and February (as used in the large industrial tariffs) will likely be unrepresentative of the customer portfolio a few months after that. In order to achieve an appropriate allocation to the LRS portfolio over the year it is proposed to recalculate an equivalent annual coincident demand on the basis of each month's actual demand of the LRS portfolio coincident with the system peak for that month. The calculation of this equivalent annual peak will reflect the differing load profiles of each customer class. It is proposed that the standby billing demand of an LRS be calculated as follows:

- To determine the firm dependable capacity requirement associated with that LRS's load:
    - Determine in each month the system peak firm demand hour;
    - Determine for that hour the total LRS's firm load in each customer class, including distribution system losses;
    - Apply the applicable adjustment factor to derive the equivalent contribution to annual coincident peak firm demand for each class; and

- Aggregate the class equivalent annual contributions to determine the LRS total equivalent annual peak firm demand.

- The firm dependable capacity contribution provided by the LRS's owned and contracted generation is the sum of contributions of firm dependable capacity of those generation facilities, excluding any such capacity assigned for self-supply of capacity-based ancillary services under the OATT, and all divided by (1 + 20% reserve margin) to determine the demand served by that capacity.
- The standby charge billing demand of the LRS is the excess of the LRS total equivalent annual peak firm demand over the firm dependable capacity contribution (after discounting for the reserve margin requirement) provided by the LRS's owned and contracted generation.
- If the firm dependable capacity contribution (after discounting) exceeds the LRS total equivalent annual peak demand, there is no payment.

5.8 Standby Service; Rate

The rate applied is the rate per unit of winter peak demand, spread over 12 monthly payments, required to recover the demand-based fixed supply cost under the Bundled Service Cost of Service analysis, after excluding those costs that are recoverable under OATT Ancillary Service rate Schedules 2 to 6.

6 Tariff Design Specifics: Transmission

6.1 Customer-specific or Aggregated Tariff

6.1.1 Concepts

NS Power has considered two conceptual options for the transmission tariff in the RtR Market Context:

- aggregated approach; and
- customer-specific approach.

These are described below. NS Power has selected the aggregate approach for the reasons also set out below.

In both cases the transmission charges would be billed by NS Power to the LRS.

6.1.2 Aggregated Approach (selected)

Under an aggregated approach, each LRS would be a transmission customer subject in general to all provisions and charges in accordance with the OATT. Charges would be determined using a demand determinant that will reflect a virtual delivery point for the aggregated of each LRS's hourly load at customer meters as adjusted for distribution losses.

OATT schedules 1,2,3,5,6,9 & 10 will apply. Schedule 4 will be replaced for each LRS by proposed Schedule 4A, as discussed below and in section 5.3.2 above.

6.1.3 Customer-specific Approach (not selected)

Under a customer-specific approach, the tariff Network Service terms and conditions would remain broadly applicable, but the service-specific schedules of rates would be replaced by class-specific schedules of rates applicable to individual customer metering results. Rates would utilise the same charge determinants as the new RtR Distribution Access Service rates, and would thus represent the transmission subset of the present Bundled Service Cost of Service analysis plus the fixed generation demand amounts allocated as recoverable under OATT Schedules 2 to 6.

Proposed OATT Schedule 4A would be separately billable to the LRS.

6.1.4 Selection

Absent a specific need to create a new customer-specific tariff with its associated immediate and ongoing administrative and regulatory burden, NS Power has adopted the aggregated tariff approach. This best leverages the use of the existing OATT, maximises consistency with the Wholesale Market, and minimises administrative burden.

6.2 Treatment of Imbalance, OATT Schedule 4

Under the proposed EBS tariff approach, OATT Schedule 4 will not apply to RtR service. It will be replaced by Schedule 4A which would provide for payments at 10% of marginal cost in respect of each MWh in excess of 2.0 MWh by which an LRS hourly generation forecast does not match the actual production, excluding when such mismatch is due to NS Power's curtailment of the generation. Please refer for discussion to section 5.3.2 above.

6.3 Relief in Respect of Generation and Load Connected in the Same Distribution Zone

Consideration has been given to the transmission tariff treatment where RtR generation and load are connected to the same distribution zone, and thus behind the same transmission delivery point. Following initial stakeholder discussion, a stakeholder took the position that if a generator-to-LRS-to-customer system were to be designed with 100% of the generation and consumption taking place on a single distribution network, then the LRS payment for transmission services should be based on the net of load minus same-zone generation.

While such an approach would address the situation where 100% of an LRS's activity is in a single zone, the principles are applicable to any situation where a portion of an LRS's generation and load are in the same zone.

The following issues were considered:

- Use of Transmission for Delivery of Services

  The delivery to the LRS for its customers of Standby Service, Top-up Service and potentially the acceptance of spill all rely on the use of the transmission system. Absent assured 100% reliable delivery of firm energy from the generator, there are expected to be occasions during RtR generator outages when the top-up requirement will be 100% of the load, allowing no reduction in transmission capacity required to that delivery point.

- Ancillary Service Requirements

  The requirement for and use of ancillary services such as system dispatch, load following and operating reserve is not reduced by co-location of generation and load within the same zone.

- Congestion Relief

  Transmission congestion does not generally arise in the last kilometers of transmission delivery, but at a few locations on the Province's bulk transmission system. While there may be differences in impact between RtR generation located in Cape Breton and in the Halifax area, those impacts do not change if the generation is connected to transmission or distribution systems in each location.

- Loss reduction

  There are arguments that generation delivered to load within the same distribution zone should not have to bear the burden of transmission system losses. However, network service transmission relies on the use of average loss factors. The loss factors used by NS Power are averages that reflect that some of their own generation may be similarly located in the same zone as load. In addition, and depending on the particular location, the addition of generation into a distribution zone may change system flows in a way that does not reduce total system losses. It would therefore not be appropriate to use different loss factors according to generator connection point.

- Embedded Cost Recovery

  To the extent that an LRS was to be relieved of transmission charges for generation located in the same zone as load, and this loss of NS Power revenue could not be recovered from Bundled Service customers, this would add to the embedded costs requiring to be recovered from the LRS. It would become necessary to add a transmission cost element to the RtR Market Transition Tariff. This would substantially negate any benefit that an LRS might gain from relief in respect of transmission charges for generation located in the same zone as RtR load.

For all of these reasons, the OATT charge determinant applicable to each LRS should be derived from the aggregate of all RtR customers' metered consumption, adjusted for distribution losses, without offset in respect of any generation located in the same distribution zone as RtR load.

7 Tariff Design Specifics: Distribution & Retail Charges

The Distribution Access Tariff provides for the recovery of costs classified in the Bundled Service Cost of Service analysis as distribution costs and as retail costs.

The Distribution Access Tariff will use the same customer demand and / or energy charge determinants as are applicable to that customer under the applicable class Bundled Service tariff.

The terms and conditions of the Distribution Access tariff will incorporate the NS Power Regulations as amended to account for the RtR market opening.

8 Tariff Design Specifics: Embedded Cost Recovery

8.1 Purpose of the RtR Market Transition Tariff

The proposed RtR Market Transition Tariff (RTT) is designed to recover embedded costs not otherwise recovered thought the tariffs described above. The amounts to be recovered under the RTT in respect of embedded costs comprise:

- The amounts under the demand element for fixed generation costs under the existing Bundled Service tariff that would be foregone as a result of capacity self-supplied by the LRS (ie excluding that recovered as Standby Service charge), minus the benefit of avoided or deferred generation capacity investment, if any[11].
    - This is effectively the Standby Service charge rate multiplied by the LRS self-supplied firm dependable capacity, less any benefit that can be gained in the form of avoided or deferred generation capacity investment. That avoided or deferred investment benefit is expected to be minimal in the near future.
    - This element of the stranded amount is principally determined by the LRS's generation resources, and is not affected under any normal conditions by its load.

[11] NS Power's integrated system plans indicate no new capacity investments until at least the mid 2020s, and therefore no opportunity until then for such avoidance or deferral.

- The foregone amounts under the energy-based charge for fixed generation costs under the Bundled Service tariffs, less that recovered in the top-up charge, minus any mitigation achieved as margin on sales of freed-up production capability.
    - This is effectively the energy based charge rate for fixed generation costs as included in the top-up charge multiplied by the LRS load supplied other than through top-up, less an estimate of mitigation expected to be achievable.
    - This element of the stranded amount is determined by the LRS's load and the nature of the generation supplying it (which affects the quantity of top-up required to support that load).
- Differences between the Bundled Service tariff fuel cost recovery foregone, and the avoided cost arising from RtR supply;
    - The present avoided cost estimates represent the incremental fuel cost associated with the displaced generation. This incremental fuel cost is presently higher than the average fuel cost shown in the Bundled Service Cost of Service analysis. This results in a reduction to the RTT energy charge.
    - The incremental fuel costs presently exceed the average fuel cost for a number of reasons:
        - The least efficient generation would likely be displaced first;
        - Hydroelectric facilities have no fuel cost and reduce the system average fuel cost;
        - The upward averaging caused by the inclusion of renewable PPA purchases is less than the previous two effects.

Should average fuel costs increase in future above incremental fuel costs, then this adjustment would add to the RTT energy rate.

This element of the stranded amount is determined by the LRS's load net of top-up. It is thus affected primarily by the LRS's load, but also by its generation resources.

8.2 Recovery Mechanism

8.2.1 Options

Two potential recovery mechanisms were presented to stakeholders:

- A Retail Access Adjustment based on the extent of the embedded cost recovery required in each year as a result of each LRS's activity, using rates that could be adjusted from time to time; or
- An exit fee associated with each exiting customer, applicable on exit and set to recover estimated embedded cost recovery requirements in respect of each exiting customer. The exit

fee would be based on each customer's historic load and class, using a rate that might be adjusted from time to time but without retroactive adjustment.

8.2.2 Retail Access Adjustment

Characteristics of the retail access adjustment as proposed in the RtR Market Transition Tariff are:

- Charges per unit of stranded demand and energy set in advance and capable of annual adjustment;
- Charge rates are indifferent to an LRS's generation technology, or to the generation deemed to be associated with each customer;
- The quantum of monthly charge would vary with changing balances in an LRS's generation and load portfolios;
- The LRS cost responsibility moves with customers on migration between LRSs, and terminates on any return to Bundled Service;
- Charges per unit are capable of adjustment to reflect new fixed cost additions and new opportunities for NS Power avoidance or deferral of investments or other costs;
- Charges are complementary to EBS and Standby Service tariffs to achieve appropriate and stable cost recovery in total, minimising risks of under- or over-recovery; and
- Capable of continuation for as long as embedded cost recovery is required, and cessation when such embedded cost recovery is no longer required.

8.2.3 Exit fee

Characteristics of an exit fee would be:

- Predetermined for each customer on exit;
- Charges per unit of historic energy consumption and demand set for each customer class in advance and capable of annual adjustment for application to new exit;
- Requires estimate on customer exit of:
    - Impact of specific generation technology expected to serve that customer,
    - Future demand-supply balance, including as a result of RtR generation development,
    - Duration of stranding, recognising limited opportunity for investment avoidance or deferral for many years;
- There is material uncertainty and risk in such estimates, with potential for under- or over-recovery;
- Requires initial cash payment, unless covered by a deferred payment mechanism (with associated financing cost); and
- Would require definition of customer / LRS responsibilities; any customer responsibility would presumably require declaration in marketing materials and comparisons.

8.2.4 Stakeholder input

One stakeholder indicated a preference for an Exit Fee, determined on customer exit but payable over a five year period.

This preference was recognised and considered in selecting the solution, but did not outweigh the fundamental reasons for the selection of the RTT approach as set out in the following section.

8.2.5 Basis for selection

The amount of embedded cost recovery depends in large part on the amounts of NS Power fixed costs recovered by other mechanisms. As noted in the discussion of the EBS and Standby Service tariffs, the amounts recovered under those tariffs depend on RtR load, RtR generation and the relationship between those two. The RTT as proposed mirrors those tariff recoveries. It can effectively avoid material under- or over-recovery and thereby best fulfil the requirements of the *Electricity Act*.

Retail Access Adjustments and Exit Fees could each in theory be set at levels that would target full embedded cost recovery, avoiding either over-recovery or under-recovery. The Exit Fee however depends on estimates, and such estimates will have to recognise the potentially long duration of the embedded cost recovery requirement in Nova Scotia due to the very limited opportunities to defer or avoid investments. Exit Fee estimates would probably be specific to each customer class, would each be specific to generation technology and would have to incorporate assumptions about EBS and Standby Service recoveries which depend on the LRS's supply-demand balance over the duration. Exit Fee estimates would have a high degree of uncertainty, and would add very significantly to the risk profile of NS Power and potentially of each LRS.

The retail access adjustment mechanism, in the form of the proposed RtR Market Transition Tariff, was selected over the Exit Fee mechanism due to its ability to achieve embedded cost recovery on a full and fair basis with the least risk and uncertainty.

8.3 Interaction with Other Tariffs and Retailers Regulations

In the event that NS Power's recoveries under other proposed tariffs are varied from those proposed, the proposed RTT would need to be revised to reflect any such changes in those other tariffs in order that it continue to fulfill the "no harm" requirements of the *Electricity Act*.

As noted in section 3.5 above, the preferred approach to issue of B-t-M settlement, as included in NS Power's Application, is based on the use of secondary metering for settlement of RtR tariff amounts including for Distribution Access Service. Were this approach to be rejected, there would need to be a wide-reaching Behind-the-Meter Transition Tariff developed and put in place to achieve the recovery of those additional embedded costs for which charges under the above tariffs would otherwise be avoided.

9 Connection issues

9.1 Transmission System Cost Impact

The present Generator Interconnection Procedures (GIP) collectively have the effect that network upgrade costs incurred to accommodate a new generation connection will initially be funded by the generator, but then recovered from customers. The recovery from customers of network upgrade costs to accommodate new RtR generation would be inconsistent with the requirements of the Electricity Act. As a result, it will be necessary to amend the GIP and Generator Interconnection Agreement (GIA) to eliminate the provision for cost recovery from customers and credit to generators in respect of RtR generation.

9.2 Other Generator Impact

In addition to other NS Power customers, the *Electricity Act*,as amended, stipulates that existing independent power producers and approved feed-in-tariff producers (collectively "protected producers") should not be negatively affected.

Potential adverse effects that might arise due to technical interactions (eg fault level requirements) should be adequately addressed by the connection processes. Potential negative effects that could arise due to transmission congestion need to be addressed. Either:

a) Physical protection, whereby protected producers should not be subject to additional curtailment as a result of RtR generation, or

b) Financial protection, whereby any losses suffered by protected producers as a result of any additional curtailment should be compensated, and the funds for such compensation should come from the RtR supply chain and not ultimately from NS Power customers.

Curtailment events are most likely to arise in order to mitigate system oversupply. They may also arise under abnormal conditions, or over time due to changing patterns of load[12].

Option (a) should be the preferred option. Administration of this solution requires that the NS Power System Operator prioritise curtailments so that all RtR generators contributing to an oversupply situation be curtailed before any protected generators contributing to that oversupply situation. This avoids situations where protected generators suffer any increase in curtailment due to the operations of RtR generators. NS Power System Operator will incorporate these processes into its Operating Procedures.

[12] NRIS resources would be connected only if they made no material contribution to transmission congestion or if they pay for the network upgrade to offset such congestion.

Each LRS would be expected to ensure that any such curtailment would not jeopardise fulfillment of its compliance obligations under the Retailers Regulations.

Appendix A: Resume of Robert Cary

PROFILE

Robert Cary & Associates Inc. is a consulting business specializing in electricity markets and related commercial issues. Robert Cary is a well-respected consultant in the electricity sector in Ontario and the Maritimes and has previous experience in the development and management of capital projects. Robert Cary has joined Charles River Associates as a senior consultant, and thus undertakes certain work through CRA and certain work independently.

Expertise covers three core areas:

- ♦ Consulting in market evolution and development in Ontario and the Maritime Provinces, including market rules development and evolution, system coordination or integration, renewable energy integration, renewable energy trading frameworks, Feed-In Tariff arrangements, clean energy standard offer programs, and greenhouse gas issues.
- ♦ High value consulting in commercial and regulatory aspects of the Ontario electricity sector. This is principally from the perspective of generators or on behalf of the OPA in connection with generation contracts, and includes the analysis to support project development and financing, market interaction, contract negotiation, regulatory interfaces, and expert witness assignments for litigation and arbitration.
- ♦ Corporate & not-for profit governance: Chair of Horizon Utilities, which is the municipally owned electricity distributor for the Cities of Hamilton and St Catharines, serving 230,000 customers. Vice Chair of St Catharines Hydro Inc. For 15 years, Director of APPrO, the Association of Power Producers of Ontario. Trustee of the Niagara Health System (2010 to 2011). Previously director of companies within the Darchem group in the UK.

More detail on each area is provided on the following pages.

Rob graduated from the University of Cambridge in England, is a Professional Engineer, and an MBA. He has undertaken project management, business and corporate development functions, largely in the energy sector. He has been associated with the Ontario electricity sector since 1990, first for AGRA Monenco, then for Westcoast Power, and since 2000 as an independent consultant.

QUALIFICATIONS

MA (physics & engineering) University of Cambridge, England, 1970
MBA, Cranfield School of Management, England, 1978
P Eng (Ontario)
Chartered Director

SELECTED POLICY DEVELOPMENT AND MARKET DESIGN ASSIGNMENTS

Atlantic Provinces / Maritime region (2001 to date)

Atlantic Region coordination: reports to the Council of Atlantic Premiers energy committee on the opportunities for greater regional integration and on the lessons to be learned from review of electricity sector governance systems elsewhere.

New Brunswick Electricity Market Design: engaged by the Government of New Brunswick to draft New Brunswick market rules in accordance with the design framework established by the Market Design Committee. Follow-on engagements to assist the New Brunswick System Operator in its development of the Market Procedures for rules implementation, including training of Market Advisory Committee members, System Operator staff, and Market Participants and in 2006 to review the opportunities for demand-management participation in the electricity market.

Nova Scotia Electricity Market Design: independent review of the recommendations of the Nova Scotia Electricity Marketplace Governance Committee with respect to achievement of Energy Policy objectives, and to practicality; advice to NSPI on tariff design issues and market documentation; drafting of market rules for the Nova Scotia electricity market for the Nova Scotia Department of Energy under the oversight of a steering committee including stakeholder representation.

Nova Scotia Renewable Energy trading system design: preparation of discussion papers to outline options for implementation of renewable electricity trading systems, followed by leadership of discussion forum, collation of stakeholder responses, and finalization of policy options as a basis for possible legislation and regulation. Assistance in determining terms of reference for a wind power integration study.

Ontario (1999 – date)

Member of the IESO (then IMO) Technical Panel, as stakeholder representative for generators from 1999 to 2004, which period encompassed the development of the market rules in preparation for market commencement and the refinement of the rules thereafter.

Direct participation in IESO working groups on behalf of generator clients to develop the market evolution program with respect to resource adequacy, system optimization, outage management, reliability and market pricing issues, Day-Ahead Market design, wind generation dispatch, capacity markets, etc.

Direct participation in OEB processes to define and later review the transmission system code and to resolve a range of regulatory issues concerning retail & distribution. Participated in IESO tariff hearings and indirectly in transmission tariff hearings.

Nova Scotia Renewable to Retail market design: consulting services to Nova Scotia Power to assist in their development of a mandated renewable to retail market framework in accordance with legislation.

SELECTED COMMERCIAL & REGULATORY CONSULTING ASSIGNMENTS

Generation owners and developers (2000 to date)

Sithe Global and Goreway Power Station: bid support, contract negotiation, project financing support, market interface preparation, and IESO audit response for the 840 MW Goreway combined cycle facility.

Macquarie / Capstone / Cardinal Power: NUG contract amendment, market readiness, successor contract analysis and negotiation support for the 156 MW combined cycle cogeneration facility.

GTAA cogeneration project performance review and ongoing support.

Consortium of all existing large wind generation owners: Took a lead role in the negotiation of market rule changes and contract amendments to enable dispatchability of wind projects.

Member of lenders independent engineer teams for review of market interface issues related to combined cycle and peaker projects under consideration for project financing.

Ontario Power Authority, now merged into the IESO (2007 to date)

Assistance in the development of:

- a generic form of peaker contract based on previous Clean Energy Supply contract models;
- Feed-in-Tariff (version 1) rules and contracts, and associated arrangements; and
- Clean Energy Standard Offer Program / CHP Standard Offer Program.

Assistance in the negotiation of:

- Lower Mattagami Hydroelectric supply agreement negotiations with OPG for the supply of electricity from the 450 MW expansion of the Lower Mattagami system;
- Early Movers successor contract negotiations, supporting the OPA in contract negotiations with early mover owners of gas fired combined cycle generators;
- Hydroelectric Contract Initiative contract development and negotiations, supporting the OPA in these contract developments and negotiations;
- Atikokan biomass conversion contract, supporting the OPA in the negotiation of a long term energy supply agreement with OPG for the conversion of Atikokan to biomass fuel;
- Lennox long term energy supply agreement, supporting the OPA in the negotiation of a long term capacity agreement with OPG for the oil/gas fuelled Lennox Generating Station; and
- Energy storage program, supporting the OPA in the development of the RFQ, RFP and contract for energy storage projects.

Assistance to the OPA in understanding how potential GHG regulation may affect gas fired facilities under contract with the OPA, and in the development of the OPA's policies for treatment of GHG regulation impacts within such contracts.

SELECTED LITIGATION & DISPUTE RESOLUTION ASSIGNMENTS

Expert witness services in support of an independent generator in Ontario in arbitration of a dispute with its gas supplier concerning the continuance of the gas price determination following restructuring of the Ontario electricity market.

Expert witness services in support of an independent generator in Ontario in mediation of a dispute with its gas supplier concerning the continuance of the gas contract and its price determination following restructuring of the Ontario electricity market.

Expert witness services to an independent generator in preparation for its defence against litigation from gas suppliers on gas price determination and contract validity, and assistance in negotiation of a settlement.

Expert witness services to an independent generator in arbitration of a dispute with its gas supplier concerning the detail of gas price determination following restructuring of the Ontario electricity market.

Expert Witness services to a generator in preparation for arbitration over contract cancellation.

DIRECTOR OF BUSINESS AND OTHER CORPORATIONS

St Catharines Hydro Inc (2000 to date)

Director and Vice Chair of St Catharines Hydro Inc, and director of St Catharines Hydro Generation Inc, which operates one hydraulic generating station and is developing a second.

Chair of St Catharines Hydro Utility Services Inc from its corporatization in July 2000 to its amalgamation with Hamilton Hydro Inc in 2005 to form Horizon Utilities Corporation. Co-chair of the joint Board Steering Committee overseeing due diligence and negotiations of the merger.

Horizon Utilities Corporation (2005 to date)

Appointed as director following the creation of Horizon Utilities Corporation from the amalgamation of St Catharines Hydro Utility Services Inc and Hamilton Hydro Inc. From 2006 to 2012, chair of Horizon Utilities Corporation HR & Governance committee. Since Feb 2012, Chair of Horizon Utilities, Horizon Holdings Inc and Horizon Energy Solutions Inc.

APPrO, Association of Power Producers of Ontario (1999 – 2014)

APPrO is a non-profit association of corporate and individual members, including all the significant electricity generators in Ontario. It works to further its members' interests and to promote competitive and environmentally friendly generation. The directors are elected by the members.

Trustee – Niagara Health Service (2010 – 2011)

Appointed in 2010 to the Board of Trustees of the Niagara Health System, and in 2011 elected as Vice-Chair.

NOVA SCOTIA POWER INCORPORATED

DISTRIBUTION TARIFF

As Approved by the UARB on ●

Nova Scotia Power Distribution Tariff

TABLE OF CONTENTS

Contents

NS Power Distribution Tariff

1. DEFINITIONS

In this Distribution Tariff, the following terms shall have the following meanings:

Act: The *Electricity Act*, S.N.S. 2004, c. 25, as amended from time to time.

Ancillary Services: Services that are necessary to support the transport of capacity and energy from generation resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Board: The Nova Scotia Utility and Review Board.

Bundled Service: Electrical service taken from NS Power under NS Power tariffs approved by the Board. This takes the form of having generation, transmission, distribution, Ancillary Services and all other items associated with the provision of such service blended or bundled within the rate. For certainty, Bundled Service does not include services taken from NS Power under the Distribution Tariff, the Energy Balancing Service Tariff, the Standby Service Tariff or the Renewable to Retail Market Transition Tariff.

Customer Information: Information including, but not limited to, the name, telephone number, mailing address, e-mail address, service address, site contact name, site contact telephone number and information regarding electricity consumption, class of service and payment history of a Retail Customer or an RtR customer, as applicable.

Demand Side Management Recovery Charges: Costs of demand side management programs that NS Power is entitled to recover from RtR Customers.

Distribution System: NS Power's facilities and equipment (generally rated at less than 69 kV) used to distribute electricity to ultimate usage points such as homes and industries either directly from nearby generators or from interchanges from the Transmission System.

Distribution System Access: The services provided by NS Power to the RtR Customer under the Distribution Tariff provide for the connection of the RtR Customer to the Distribution System, but does not include the provision of electricity. These services are comprised of delivery of electricity on the distribution system and related services including connections, disconnections, line and service extensions, inspection services, meter services, power restoration, meter reading, and customer service, all in accordance with applicable NS Power Regulations.

Distribution Tariff: This Distribution Tariff, its terms and conditions and all appendices and attachments referenced herein, including the Distribution Tariff Rate Schedules.

Distribution Tariff Rate Schedules: The rate schedules attached hereto as Appendix A which outline the pricing and availability provisions for Distribution System Access.

DT Charges: This term shall have the meaning set out in Section 11.2.

Good Utility Practice: Those practices, methods or acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America) that at a particular time, in the exercise of reasonable judgment, would have been expected to accomplish the desired result in a manner consistent with regulations, reliability, safety, environmental protection, economy and expedition as applied and practiced in the utility industry with respect to power generation, delivery, purchase and sale.

Licenced Retail Supplier (LRS): A Retail Supplier who:

(a) holds a valid Retail Supplier Licence; and

(b) has a valid LRS Participation Agreement executed with NS Power.

For certainty, a Wholesale Customer is not a Licenced Retail Supplier.

LRS Participation Agreement: The agreement (and any amendments or supplements thereto) between a Licenced Retail Supplier and NS Power with respect to the sale of renewable low-impact electricity by the LRS in the form approved by the Board.

NS Power: Nova Scotia Power Incorporated.

NS Power Regulations: NS Power Regulations approved by the Board pursuant to the *Public Utilities Act* (Nova Scotia) as such regulations may be amended from time to time with the approval of the Board.

Open Access Transmission Tariff (OATT): NS Power's Open Access Transmission Tariff, as approved by the Board.

Province: Province of Nova Scotia

Real Power Losses: Resistive losses occurring as the result of current flow through primary distribution feeders, distribution transformers, secondary conductors and service drops.

Reasonable Efforts: With respect to an action required to be attempted or taken by a party, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a party would use to protect its own interests.

renewable low-impact electricity: This term has the same meaning as in the Renewable Electricity Regulations (Nova Scotia).

Retail Supplier: This term has the same meaning as under the Act.

Retail Supplier Licence: A Retail Supplier licence issued by the Board in accordance with the Act and regulations made thereunder which authorizes a person to sell renewable low-impact electricity generated within the Province.

Retail Customer: This term has the same meaning as under the Act. For certainty, a customer of a municipal utility (as defined under the Act) is not a Retail Customer for the purposes of this Distribution Tariff.

RtR Customer: A Retail Customer who is acquiring renewable low-impact electricity from an LRS at an individual RtR Customer Premises and is not receiving Bundled Service from NS Power at that RtR Customer Premises.

RtR Customer Premises: A premises that is provided with electricity through a single meter and, as the context requires, either:

(a) a complete building such as an office building, factory or house; or

(b) a part of a building such as a suite of offices in an office building or an apartment in an apartment building, and in such cases the part of the building occupied must be contiguous and include no space not controlled by the customer; or

(c) a group of buildings served by one electric service and at its discretion accepted by NS Power as one RtR Customer for LRS billing purposes.

RtR Customer Transaction Request Application: A NS Power document to be used by a Licenced Retail Supplier for the purpose of applying to NS Power to accept and process RtR Customer transactions.

Transmission Provider: NS Power.

Transmission Services: The services obtained by market participants under the terms and conditions of the OATT to access the Transmission System for the purpose of transporting electric energy and Ancillary Services.

Transmission System: The facilities, generally rated at 69 kV and above, owned, controlled or operated by the Transmission Provider that are used to provide transmission service under the OATT.

Wholesale Customer: This term has the same meaning as under the Act.

2. PURPOSE OF THE DISTRIBUTION TARIFF

In accordance with the provisions of the Act and the regulations made thereunder, NS Power will, subject to the terms of this Distribution Tariff, provide Distribution System Access to RtR Customers to enable the connection of the RtR Customer to the Distribution System.

3. SCOPE OF THE DISTRIBUTION TARIFF

The Distribution Tariff is applicable to all RtR Customers connected to the Distribution System.

This Distribution Tariff is not applicable to RtR Customers directly connected to the Transmission System. Transmission-connected RtR Customers must have their Transmission System access arranged by the LRS under the provisions of the OATT.

The Distribution Tariff outlines the terms and conditions that apply to the provision of Distribution System Access to RtR Customers.

The Distribution Tariff Rate Schedules apply to the provision of Distribution System Access.

4. BOARD APPROVAL

The Distribution Tariff has been approved by the Board.

Nothing contained in the Distribution Tariff shall be construed as affecting in any way the right of NS Power to make application to the Board for a change in any rates (including the Distribution Tariff Rate Schedules), terms and conditions, charges, classification of service, rules or regulations.

5. APPENDICES

For greater certainty, Appendix A attached hereto forms part of the Distribution Tariff.

6. APPLICABILITY OF NS POWER REGULATIONS TO THE RTR CUSTOMER

The NS Power Regulations apply to an RtR Customer receiving Distribution System Access.

7. NS POWER RESPONSIBILITIES

NS Power shall be responsible for:

(a) provision of Distribution System Access;

(b) processing RtR Customer Transaction Request Applications that are received from an LRS on behalf of the RtR Customer;

(c) providing billing data for the RtR Customer’s Distribution Tariff charges for inclusion on the RtR Customer’s invoice; and

(d) acting as the point of contact for RtR Customers for matters related to the provision of Distribution Access Service.

NS Power shall not be responsible to the RtR Customer for the supply of electricity (whether renewable low-impact electricity or otherwise) which the RtR Customer shall be obligated to obtain from an LRS.

NS Power shall not be responsible for monitoring, reviewing or enforcing contracts or arrangements between the RtR Customer and the LRS and shall not be liable for any loss, damages, cost, injury, expense or other liability, whether direct, indirect, consequential or special in nature, howsoever caused, as a result of the LRS's failure to perform its obligations to its RtR Customer(s).

8. RtR CUSTOMER RESPONSIBILITIES

The RtR Customer shall be responsible for:

(a) payment of all fees and charges arising in connection with the Distribution Tariff;

(b) compliance with the terms and conditions of the Distribution Tariff and the NS Power Regulations;

(c) obtaining a supply of renewable low-impact electricity from an LRS; and

(d) all contractual arrangements with an LRS for the supply of renewable low-impact electricity.

9. INTERRUPTION OF DISTRIBUTION SYSTEM ACCESS

Notwithstanding any term of this Distribution Tariff, NS Power shall have the right to suspend or interrupt, in whole or in part, the provision of Distribution System Access for the purpose of safeguarding life or property, for making repairs, changes, renewals, improvements or replacements to the Distribution System provided NS Power shall make Reasonable Efforts to ensure all such suspensions or interruptions are of a minimum duration consistent with the exigencies of the case, provided, however, any such suspensions or interruptions shall not release the RtR Customer from its obligation to pay all charges pursuant to this Distribution Tariff during the period of any such suspensions or interruption and to resume the use of power and energy when the supply is restored.

9A. LIMITATION OF LIABILITY

(a) NS Power shall not be responsible for any claim, loss, cost, liability, action, judgment, suit, proceeding, expense, disbursement or damage whatsoever arising, either directly or indirectly, whether in contract or tort (including negligence) or otherwise, in respect of any interruptions, diversions, curtailments, or other procedures necessary to maintain the efficient and effective operation of the Distribution System or the Transmission System. This would include all Distribution Access Service as permitted by this Distribution Tariff.

(b) NS Power not liable for damages in respect of any delay, interruption or other partial or complete failure in supplying Distribution System Access where such damages are caused by something which is beyond the ability of the Company to control by reasonable and practicable effort.

(c) Notwithstanding any other provision herein or applicable law to the contrary, NS Power shall not be liable for:

i. any indirect or consequential loss or incidental or special damages, including, without limitation, any punitive or aggravated damages;

ii. any loss of profit, loss of contract, loss of opportunity or loss of goodwill; or

iii. damages for loss of use,

arising, directly or indirectly, with the performance or delivery of the Distribution Access Service or any other obligations of NS Power under this Distribution Tariff, including but not limited to interruptions, diversions, curtailments or suspensions of any of the Distribution Access Services or from any acts or omissions of its employees and agents, and whether arising in contract, indemnity, tort (including negligence) or any other legal theory.

10. METERING

10.1. Provision and Ownership

NS Power will provide, install and seal all revenue class meters as necessary for application of this Distribution Tariff. The meters will be used for determining charges for Distribution System Access under the Distribution Tariff applicable to the RtR Customers.

Interval meters with remote polling capability shall be installed for all RtR Customers.

All meters and associated revenue metering equipment shall remain the property of NS Power. All revenue metering equipment installations shall meet the requirements under the Electricity and Gas Inspection Act regulations in effect at the time.

RtR Customer metering requirements are set out in the NS Power Regulations Section 4 - Metering.

10.2. Meter Reading

RtR Customer meter reading requirements are set out in NS Power Regulations Section 5 – Meter Reading and Billing.

11. BILLING

11.1. Application of Distribution Tariff Rates

The Distribution Tariff amounts payable by the RtR Customer will be calculated by NS Power using the RtR Customer's meter readings and the Distribution Tariff Rate Schedule applicable to the RtR Customer's rate class.

If the operational or consumption characteristics of the RtR Customer change, such that the RtR Customer, in NS Power's determination, no longer qualifies for its current rate class, NS Power shall apply a Distribution Tariff rate appropriate to the RtR Customer's new operational or consumption characteristics.

11.2. Billing

Unless NS Power directs otherwise, the RtR Customer shall be invoiced by the LRS and will pay the LRS for any charges or fees, inclusive of all applicable taxes, owing by the RtR Customer to NS Power under this Distribution Tariff (DT Charges).

For greater certainty, the DT Charges shall include:

(a) All fees and charges for the provision of Distribution System Access under this Distribution Tariff;

(b) Demand Side Management Recovery Charges;

(c) any applicable costs incurred by NS Power resulting from performance of repairs, changes, renewals, improvements or replacements outside of normal working hours, at the RtR Customer's request; and

(d) Other items as may be approved by the Board.

NS Power Distribution Tariff

NS Power may, at its discretion, include fees for any special customer services provided at the LRS's or the RtR Customer's request, pursuant to NS Power Regulation 7.1 - Schedule of Charges.

The RtR Customer consents to NS Power providing the LRS with Customer Information for the purposes of facilitating the billing arrangements between the LRS and the RtR Customer.

The RtR Customer acknowledges and agrees that unless NS Power directs otherwise, it shall be responsible to the LRS with respect to all matters relating to the payment and collection of the DT Charges and any other amounts owing by it under this Distribution Tariff.

The RtR Customer shall not make or bring any claim, action or demand against NS Power arising out of or in any way attributable to the collection of the DT Charges by the LRS, its servants, agents or employees.

11.3. **Real Power Losses**

Distribution System Real Power Losses associated with Distribution System Access are incorporated in the Distribution Tariff rates applicable to each RtR Customer's rate class. The RtR Customer is responsible for the costs of such Real Power Losses.

12. **DISCONTINUANCE OF DISTRIBUTION SYSTEM ACCESS BY NS POWER**

For certainty, NS Power may discontinue Distribution System Access to an RtR Customer in accordance with the requirements of NS Power Regulations Section 6 – Collection of Accounts, Regulations 6.1 - Disconnection of Electric Service, 6.2 - Rules Governing Disconnection and 6.3 - Medical Emergency.

APPENDIX A: DISTRIBUTION TARIFF RATE SCHEDULES

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

Note: For certainty, all capitalized terms shall, unless otherwise defined herein, have the meanings ascribed thereto in Distribution Tariff.

APPLICABILITY

This schedule provides charges for Distribution System Access applicable to distribution-connected RtR Customers receiving supply of renewable low-impact electricity from a Licenced Retail Supplier as provided for under the Electricity Act (Nova Scotia).

CHARGES

Rate Class	**Customer Charge**	**Distribution Charge**	**Demand Charge**	**Minimum Monthly Charge**	**Transformer Ownership Credit**
	$/month	**¢/kWh**	**$/kVA**	**$/month**	**$/kVA**
Domestic Service	10.83	2.549	0.000	10.83	0
Domestic Service Time of Day	10.83	2.549	0.000	10.83	0
Small General	12.65	2.362	0.000	12.65	0
General (1)	0	0.000	5.458	12.65	-0.32
Large General (2)	0	0.000	3.361	12.65	-0.32
Small Industrial	0	0.000	4.494	12.65	-0.32
Medium Industrial	0	0.000	3.496	12.65	-0.32
Large Industrial Firm (2) Rate Code 23	0	0.000	2.430	12.65	-0.32
Outdoor Recreational Light Rate	0	3.551	0.000	0	0
Unmetered Service Rates	0	0.000	11.960	17.51	0
Miscellaneous Small Loads	0	0.000	11.960	17.51	0

Footnotes

(1) Demand Charges and credits are applicable to kilowatt (kW) demand.
(2) Demand Charges and credits are applicable to kilovolt-ampere of maximum (kVA) demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven months regardless whether service was taken under the bundled or unbundled service.

PROPOSED: September 1, 2015 EFFECTIVE:

NOVA SCOTIA POWER INCORPORATED

DISTRIBUTION TARIFF RATES*

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The same maximum per kWh charges and minimum bills will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above.

AVAILABILITY

The same Availability conditions will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above, saving and excepting the Interruptible Rider to the Large Industrial Tariff (Rate Code 25) which will not apply.

SPECIAL CONDITIONS

The same Special Conditions will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above, saving and excepting the Interruptible Rider to the Large Industrial Tariff (Rate Code 25) which will not apply.
.

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(A) **STREET AND AREA LIGHTING**

RATES

(1) **INCANDESCENT**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
001	300 and less	97	$10.78	
002	Greater than 300	154	13.09	
b) Operating Only				
003	300 and Less	97	3.74	

(2) **MERCURY VAPOUR**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
100	100	43	$10.03	
101	125	52	11.88	
102	175	69	10.77	
103	250	97	12.59	
104	400	154	14.86	
105	700	260	20.14	
106	1000	363	25.15	
107	250	212	17.74	Continuous Operation
b) Operating and Maintenance Only				
201	125	52	$8.87	
202	175	69	7.80	
203	250	97	8.90	
204	400	154	11.09	
205	700	260	15.19	
206	1000	363	19.17	
c) Operating Only				
301	125	52	$2.00	
302	175	69	2.64	
303	250	97	3.74	
304	400	154	5.93	

PROPOSED: September 1, 2015 EFFECTIVE:

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

305	700	260	10.03
306	1000	363	14.01

(3) **FLUORESCENT**

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	$/Mo.	Other
a)	Operating, Maintenance and Capital (Full Charge)				
110	24	2	30	13.91	
111	48	2	85	16.28	
112	72	2	116	17.96	
113	72	4	222	23.16	
114	96	1	47	15.08	
115	72	1	60	15.21	
116	48	4	166	19.99	
b)	Operating and Maintenance Only				
213	72	4	222	$18.86	
214	96	1	47	12.11	
215	72	1	60	12.63	
216	48	4	166	16.74	
217	48	1	49	12.18	
218	48	2	85	13.59	
c)	Operating Only				
330	35	4	47	1.80	

PROPOSED: September 1, 2015 EFFECTIVE:

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(4) **FLUORESCENT CROSSWALK**

a) Continuous Burning - Operating Only

117	72	4	486	$8.56
118	24	2	66	1.15
119	48	4	364	6.43
120	96	2	254	4.49
150	96	4	613	10.80

PROPOSED: September 1, 2015 EFFECTIVE:

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(4) **FLUORESCENT CROSSWALK (cont.)**

b) Photocell Operation - Operating Only

310	24	2	30	$1.17
311	48	4	166	6.43
312	72	2	116	4.50
313	72	4	222	8.55
314	96	1	47	1.80
315	72	1	60	2.32
350	96	4	280	10.82

(5) **LOW PRESSURE SODIUM**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
130	135	60	$23.58	
131	180	80	26.94	
132	90	45	22.99	
b) Operating and Maintenance Only				
231	180	80	18.56	
c) Operating Only				
331	180	80	3.09	

(6) **HIGH PRESSURE SODIUM**

a) Operating, Maintenance and Capital (Full Charge)

121	250	100	$12.23	
122	400	150	14.28	
123	70	32	9.41	
124	100	45	9.93	
125	150	65	10.89	
126	100	99	15.08	Continuous Operation

PROPOSED: September 1, 2015 EFFECTIVE:

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(6) **HIGH PRESSURE SODIUM (**cont'd)

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
b)	Operating and Maintenance Only			
221	250	100	$9.02	
222	70	32	6.39	
223	100	45	6.89	
224	150	65	7.67	
c)	Operating Only			
321	250	100	$3.86	
322	70	32	1.23	
323	100	45	1.73	
324	150	65	2.51	
326	400	150	5.79	
327	500	183	7.07	
328	1000	363	14.02	
329	1500	500	19.30	

(7) **METALLIC ADDITIVE**

a)	Operating, Maintenance and Capital (Full Charge)		
140	400	150	$17.85
141	1000	360	31.83
142	250	100	19.98
143	150	67	18.70
144	100	50	18.05
b)	Operating Only		
341	1000	360	$13.89
342	400	150	5.79
343	250	100	3.86
344	175	75	2.89
345	150	67	2.58
346	100	50	1.93

PROPOSED: September 1, 2015 EFFECTIVE:

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(8) **LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY**

Rate Code	$/Mo.	Other
530	$0.06	Non – Continuous
531	$0.09	Continuous

(9) **LIGHT EMITTING DIODE (LED) – Operating Only**

Rate Code	Watts	kWh/Mo.	$/Mo.
532	44	15	$0.58
533	66	22	0.85
534	88	29	1.12
535	92	31	1.20
536	105	35	1.35
537	170	57	2.20
539	110	37	1.43
540	65	22	0.85
541	55	18	0.69
542	83	28	1.08
543	48	16	0.62
544	72	24	0.93

(10) **INTERIM LIGHT EMITTING DIODE (LED) – Operating & Capital Only***

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
615	44	15	$7.85	
616	55	18	7.96	
623	28	9	7.62	
624	50	17	7.93	
625	72	24	8.20	
626	100	33	8.54	
627	200	67	9.86	

* While fixture maintenance costs associated with LED streetlights may occur, this component is currently not reflected in the rates.

PROPOSED: September 1, 2015 EFFECTIVE:

PROPOSED DISTRIBUTION TARIFF AS BASED ON 2014 COSS

RESIDENTIAL TARIFFS

Domestic Service Rate		units	Current Bundled Rate	Proposed Distribution Rate	% change
Customer Charge		$/mo	10.830	10.830	0.0%
Energy Charge		¢/kWh	14.251	2.549	-82.1%
Domestic Service TOD Rate					
Customer Charge		$/mo	18.820	10.830	-42.5%
December, January & Feb: energy charge					
	on-peak	¢/kWh	18.609	2.549	-86.3%
	shoulder	¢/kWh	14.251	2.549	-82.1%
	off-peak	¢/kWh	7.324	2.549	-65.2%
Other months: energy charge					
	on-peak	¢/kWh	14.251	2.549	-82.1%
	off-peak	¢/kWh	7.324	2.549	-65.2%

COMMERCIAL TARIFFS

Small General Rate	units	Current Bundled Rate	Proposed Distribution Rate	% change
Customer Charge	$/mo	12.650	12.650	0.0%
Energy Charge, block 1 (first 200 kWhs)	¢/kWh	15.092	2.362	-84.3%
Energy Charge, block 2	¢/kWh	13.278	2.362	-82.2%
General Rate				
Demand Charge	$/kW	10.497	5.458	-48.0%
Energy Charge, block 1 (first 200kWh * demand)	¢/kWh	11.208	-	-100.0%
Energy Charge, block 2	¢/kWh	7.929	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Large General Rate				
Demand Charge (Ratcheted)	$/kVA	13.345	3.361	-74.8%
Energy Charge	¢/kWh	8.029	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%

INDUSTRIAL TARIFFS

Small Industrial Rate	units	Current Bundled Rate	Proposed Distribution Rate	% change
Demand Charge	$/kVA	7.714	4.494	-41.7%
Energy Charge, block 1 (first 200 kWhs * demand)	¢/kWh	10.090	-	-100.0%
Energy Charge, block 2	¢/kWh	7.707	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Medium Industrial Rate				
Demand Charge	$/kVA	12.501	3.496	-72.0%
Energy Charge	¢/kWh	7.241	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Large Industrial Rate				
Demand Charge (Ratcheted)	$/kVA	11.995	2.430	-79.7%
Energy Charge to firm Customers	¢/kWh	7.620	-	-100.0%
Energy Charge to interruptible customers		7.222	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Interruptible Credit	$/kVA	(3.430)	(3.430)	0.0%

OTHER TARIFFS

Outdoor Recreational Light Rate	units	Current Bundled Rate	Proposed Distribution Rate	% change
Energy Charge	¢/kWh	14.354	3.551	-75.3%
Miscellaneous Small Loads Rate				
Demand Charge	$/kW	11.777	11.960	1.55%
Energy Charge, block 1 (first 200kWh * demand)	¢/kWh	13.467	-	-100.00%
Energy Charge, block 2	¢/kWh	8.941	-	-100.00%

September 1, 2015 Note: this is a revision to the
Spreadsheet issued as Attachment D on May 21, 2015.
Refer to Multeese DR-21 issued July 3, 2015

Proposed Distribution Tariffs	Distribution Usage in KWhs			Demand in kWs or kVa			Base Charge			PROPOSED
Above-the-line Classes	Energy in GWh -	Per KWh Charge	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	RATES FORECAST 2014
Residential Sector										
Non-ETS	3,993.3	$ 0.02549	$ 101.8	NA	NA	NA	5.1	$ 10.83	$ 55.4	$ **157.2**
ETS	223.2	$ 0.02549	$ 5.7	NA	NA	NA	0.1	$ 10.83	$ 1.6	$ **7.3**
Total	**4,216.5**		**$ 107.5**	**NA**	**NA**	**NA**	**5.3**		**$ 56.99**	$ **164.5**
Commercial Sector										
Small General	236.7	$ 0.02362	$ 5.6	-		$ -	0.3	$ 12.65	$ 3.6	$ **9.2**
General Demand	2,448.7	NA	NA	7.0	$ 5.458	$ 38.2	-	$ -	$ -	$ **38.2**
Large General										
Without Trans. Own.	245.8	NA	NA	0.5	$ 3.361	$ 1.7				$ **1.7**
With Trans. Own.	133.8	NA	NA	0.3	$ 3.041	$ 1.0				$ **1.0**
Sub-total	379.6	NA	NA	0.9		$ 2.8				$ **2.8**
Total	**3,065.0**		**$ 5.6**	**7.9**		**$ 41.0**	**0.3**		**$ 3.6**	$ **50.2**
Industrial Sector										
Small Industrial	255.9	NA	NA	1.0	$ 4.494	$ 4.5				$ **4.5**
Medium Industrial	495.4	NA	NA	1.4	$ 3.496	$ 5.0				$ **5.0**
Large Industrial Firm		NA	NA							
Without Trans. Own.	46.3	NA	NA	0.1	$ 2.430	$ 0.3				$ **0.3**
With Trans. Own.	-	NA	NA	-	$ 2.110	$ -				$ **-**
Sub-total	46.3	NA	NA	0.1		$ 0.3				$ **0.3**
Large Industrial Interr.										
Without Trans. Own.	176.4	NA	NA	0.5	$ 2.430	1.2				$ **1.2**
With Trans. Own.	52.8	NA	NA	0.3	$ 2.110	0.6				$ **0.6**
Sub-total	229.1	NA	NA	0.8		1.8				$ **1.8**
Total Large Industrial	**275.4**	**NA**	**NA**	**0.89**		**$ 2.1**				$ **2.1**
Total Industrial	**1,026.7**	**NA**	**NA**	**3.3**		**$ 11.6**	**0.0**		**0.0**	$ **11.6**
Other										
Unmetered [1,2]										
Electric Service Only	98.2	$ 0.03551	$ 3.5							$ **3.5**
Street light Fixtures										$ **8.8**
Total										$ **12.2**
Total Above-the-line	**8,406.5**		**$ 116.6**	**11.2**		**$ 52.6**	**5.5**		**$ 60.6**	$ **238.5**

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights

(2) Per kWh charge is not applicable as the class is made up of a number of rates

Nova Scotia Power

Licenced Retail Supplier

Terms and Conditions

As Approved by the UARB on ●

TABLE OF CONTENTS

DEFINITIONS

1.1 The following terms shall have the following meanings:

Act: The *Electricity Act*, S.N.S. 2004, c. 25, as amended from time to time.

Ancillary Services: Services that are necessary to support the transport of capacity and energy from generation resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Billing Period: The time between two consecutive meter readings, or estimates, or a combination thereof.

Board: Nova Scotia Utility and Review Board.

Bundled Service: Electrical service taken from NS Power under NS Power tariffs approved by the Board. This takes the form of having generation, transmission, distribution, Ancillary Services and all other items associated with the provision of such service blended or bundled within the rate. For certainty, Bundled Service does not include services taken from NS Power under the Distribution Tariff, the Energy Balancing Service Tariff, the Standby Service Tariff or the Renewable to Retail Market Transition Tariff.

Business Day: A Business Day is Monday to Friday, inclusive, excluding holidays. The regular business hours on a Business Day are from 08:30 to 16:30 Atlantic Time.

Calendar Day: Any day including Saturday, Sunday or a holiday.

Credit Assurance: Collateral in the form of cash, a Letter(s) of Credit, or other security acceptable to NS Power**.**

Credit Rating: With respect to an entity, the lowest of the ratings then assigned to such entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements), or issuer or general corporate rating.

Confidential Information: Information that is (a) designated as confidential in LRS Terms and Conditions or LRS Participation Agreement; or (b) identified in writing as confidential by the disclosing person at the time of disclosure. The following information will not constitute Confidential Information: (i) information which is or becomes generally available to the public other than as a result of a disclosure by NS Power; (ii) information which was already known to NS Power on a non-confidential basis prior to being furnished by the disclosing party; (iii) information which becomes available to NS Power on a non-confidential basis from a source other than the disclosing party or a representative of the disclosing party if such source was not subject to any prohibition against transmitting the information to NS Power and was not bound by a confidentiality agreement with the disclosing party; or (iv) information which was independently developed by NS Power or its representatives without reference to the Confidential Information.

Customer Information: Information including, but not limited to, the name, telephone number, mailing address, e-mail address, service address, site contact name, site contact telephone number and information regarding electricity consumption, class of service and payment history of a Retail Customer or an RtR customer, as applicable.

DBRS: DBRS Limited or its successor.

Demand Side Management (DSM) Recovery Charges: Costs of DSM programs that NS Power is entitled to recover from RtR Customers

Distribution System: NS Power's facilities and equipment (generally rated less than 69 kV) used to distribute electricity to ultimate usage points such as homes and industries either directly from nearby generators or from interchanges from the Transmission System.

Distribution System Access: The services provided by NS Power to the RtR Customer under the Distribution Tariff to provide for the connection of the RtR Customer to the Distribution System, but does not include the provision of electricity. These services are comprised of delivery of electricity on the distribution system and related services including connections, disconnections, line and service extensions, inspection services, meter services, power restoration, meter reading, and customer service, all in accordance with applicable NS Power Regulations.

Distribution Tariff: The NS Power distribution tariff approved by the Board which provides for Distribution System Access by the RtR Customer receiving renewable low-impact renewable electricity supplied by the LRS.

Distribution Tariff Rate Schedules: The rate schedules attached to the Distribution Tariff which outline the pricing and availability provisions for Distribution System Access.

DT Charges: Any and all charges or fees owing by the LRS' RtR Customers to NS Power under the Distribution Tariff, including applicable taxes. For certainty, the DT Charges shall include:

(a) All fees and charges for the provision of Distribution System Access;
(b) Demand Side Management Recovery Charges; and
(c) Other items as may be approved by the Board.

Energy Balancing Service Tariff: A NS Power tariff, approved by the Board, which provides supplementary generation service to Licenced Retail Suppliers for the delivery of energy to RtR Customers and reception by NS Power of surplus generation from qualifying generators through the LRS.

Good Utility Practice: Those practices, methods or acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America) that at a particular time, in the exercise of reasonable judgment, would have been expected to accomplish the desired result in a manner consistent with regulations, reliability, safety, environmental protection, economy and expedition as applied and practiced in the utility industry with respect to power generation, delivery, purchase and sale.

Letter of Credit: One or more irrevocable, transferable standby letters of credit issued by a Schedule 1 Canadian Chartered Bank with such bank having a Credit Rating of A from S&P or DBRS or A2 from Moody's (or other ratings agency acceptable to NS Power), in a form and manner acceptable to NS Power.

Licenced Retail Supplier (LRS): A Retail Supplier who:
(a) holds a valid Retail Supplier Licence; and
(b) has a valid LRS Participation Agreement executed with NS Power.
For certainty, a Wholesale Customer is not a Licenced Retail Supplier.

Load Settlement: The process used by NS Power to determine the aggregate consumption of an LRS's RtR Customers in each hour for the purpose of determining charges for services under the Energy Balancing Service Tariff, Standby Service Tariff, the Renewable to Retail Transition Tariff and for Transmission Services and Ancillary Services under the OATT.

LRS Participation Agreement: The agreement (and any amendments or supplements thereto) between a Licenced Retail Supplier and NS Power in the form attached hereto as Appendix B, which incorporates the LRS Terms and Conditions.

LRS Terms and Conditions (LRS T&Cs): This term has the meaning set out in Section 2.0 herein.

LRS Tariffed Services: The services provided to the LRS by NS Power under the Energy Balancing Service Tariff, the Standby Service Tariff, the OATT (including Transmission Service and Ancillary Services) and the Renewable to Retail Transition Tariff (RTT). For certainty, the LRS Tariffed Services exclude any services provided to the RtR Customer by NS Power under the Distribution Tariff.

Market Participant: A person who has executed a wholesale market Participation Agreement (as defined in the Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules Appendix 1A) with the NSPSO in accordance with the requirements of the Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules.

Moody's: Moody's Investors Services, Inc. or its successor.

Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules: The Wholesale and Renewable to Retail Market Rules made by the Nova Scotia Department of Energy as amended from time to time in accordance with section 2.4 of those rules.

NS Power: Nova Scotia Power Incorporated.

NS Power Regulations: NS Power Regulations approved by the Board pursuant to the *Public Utilities Act* (Nova Scotia) as such regulations may be amended from time to time with the approval of the Board.

NSPSO: NS Power System Operator.

Open Access Transmission Tariff (OATT): NS Power's Open Access Transmission Tariff, as approved by the Board.

Province: Province of Nova Scotia

Reasonable Efforts: With respect to an action required to be attempted or taken by a party, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a party would use to protect its own interests.

Renewable low-impact electricity: This term has the same meaning as in the Renewable Electricity Regulations (Nova Scotia).

Retail Customer: This term has the same meaning as under the Act. For certainty, a customer of a municipal utility (as defined under the Act) is not a Retail Customer.

Retail Supplier: This term has the same meaning as under the Act.

Retail Supplier Licence: A Retail Supplier licence issued by the Board in accordance with the Act and regulations made thereunder which authorizes a person to sell renewable low-impact electricity generated within the Province.

RtR Customer: A Retail Customer who is acquiring renewable low-impact electricity from an LRS at an individual RtR Customer Premises and is not receiving Bundled Service from NS Power at that RtR Customer Premises.

RtR Customer Contract: This term shall have the meaning set out in Section 9.1 herein.

RtR Customer Premises: A premises that is provided with electricity through a single meter and, as the context requires, either:

(a) a complete building such as an office building, factory or house; or

(b) a part of a building such as a suite of offices in an office building or an apartment in an apartment building, and in such cases the part of the building occupied must be contiguous and include no space not controlled by the customer; or

(c) a group of buildings served by one electric service and at its discretion accepted by NS Power as one RtR Customer for LRS billing purposes.

RtR Customer Transaction Request Application: A NS Power document in the form attached hereto as Appendix A to be used by the LRS for the purpose of applying to NS Power to accept and process RtR Customer transactions.

Renewable to Retail Market Transition Tariff (RTT): The NS Power tariff approved by the Board which provides for recovery from each LRS the amount of NS Power's fixed or embedded costs, including deferred costs.

S&P: The Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) or its successor.

Standby Service Tariff: A NS Power tariff, approved by the Board, which provides **s**upplemental generation capacity service to Licenced Retail Suppliers. The service has two components: (1) capacity adequacy service required meeting adequacy standards of the Nova Scotia electricity system; and (2) top-up capacity service associated with energy delivery in respect of forced or unplanned outages of the Licenced Retail Supplier's contracted generation resources.

Transmission Provider: NS Power.

Transmission Services: The services obtained by Market Participants under the terms and conditions of the OATT to access the Transmission System for the purpose of transporting electric energy and Ancillary Services.

Transmission System: The facilities, generally rated at 69 kV and above, owned, controlled or operated by the Transmission Provider that are used to provide transmission service under the OATT.

Wholesale Customer: This term has the same meaning as under the Act.

PURPOSE OF THE LRS TERMS AND CONDITIONS

2.1 These procedures and terms and conditions (collectively referred to as the "LRS Terms and Conditions" or "LRS T&Cs") are applicable to Licenced Retail Suppliers for the purpose of enabling the supply of renewable low-impact electricity to RtR Customers in accordance with the provisions of the Act and the regulations made thereunder.

SCOPE AND APPLICABILITY OF THE LRS T&CS

3.1 These LRS T&Cs are applicable to an LRS who enters into an LRS Participation Agreement with NS Power for provision of LRS Tariffed Services to the LRS.

3.2 The LRS T&Cs and are deemed to form part of the LRS Participation Agreement and address, among other things, the procedures for RtR Customer transactions, metering, Load Settlement and LRS billing.

3.3 An LRS is required to execute an LRS Participation Agreement with NS Power in order for the LRS to be eligible for LRS Tariffed Services from NS Power. The LRS Participation Agreement shall give contractual force to the LRS T&Cs with respect to the relationship between NS Power and the LRS.

3.4 Distribution System Access under the Distribution Tariff is provided directly to the RtR Customer by NS Power and is not included in the scope of the LRS Participation Agreement.

BOARD APPROVAL

4.1 The LRS T&Cs have been approved by the Board.

4.2 Nothing contained in the LRS T&Cs or the LRS Participation Agreement shall be construed as affecting in any way the right of NS Power to unilaterally make application to the Board for a change in any rates, procedures, rules or regulations, including, the LRS T&Cs, the Energy Balancing Service Tariff, the Standby Service Tariff, the OATT, the Renewable to Retail Market Transition Tariff or the Distribution Tariff.

APPENDICES

5.1 For greater certainty, the following appendices are attached to and form part of the LRS T&Cs:

(a) Appendix A: RtR Customer Transaction Request Application Form

(b) Appendix B: LRS Participation Agreement.

ELIGIBILITY OF THE LRS

6.1 Subject to the terms and conditions set out herein, an LRS shall be eligible for LRS Tariffed Services from NS Power, if the following conditions are met to the satisfaction of NS Power:

(a) LRS has a valid Retail Supplier Licence and provides NS Power with its unique licence identification number;

(b) NS Power is in receipt of a valid LRS Participation Agreement duly executed by the LRS and NS Power;

(c) LRS meets and adheres to the Credit Assurance requirements of NS Power as described in Section 18 herein; and

(d) LRS provides NS Power with confirmation that the LRS has been qualified by the NSPSO as a Market Participant within the NS Power operating area.

6.2 NS Power shall have the right to terminate the LRS Participation Agreement and discontinue the LRS Tariffed Services without liability or penalty if at any time the LRS fails to satisfy any of the conditions set out in Section 6.1.

6.3 There shall be only one LRS in respect of an RtR Customer Premises at any given time.

6.4 There shall be only one (1) RtR Customer for an RtR Customer Premises at any given time.

LRS PARTICIPATION IN NS POWER TARIFFS

7.1 The LRS shall subscribe to all of the LRS Tariffed Services. For certainty, the LRS shall not be entitled to receive one or more of the individual LRS Tariffed Services without accepting and receiving all of the LRS Tariffed Services in the aggregate.

LRS RESPONSIBILITIES

8.1 The LRS shall be responsible for:

(a) the procurement of electricity from qualified low-impact renewable electricity generators;

(b) acquiring the services delivered under, and remaining in compliance with, the OATT, Energy Balancing Service Tariff, Standby Service Tariff and the Renewable to Retail Market Transition Tariff;

(c) payment to NS Power of all fees and charges for the LRS Tariffed Services;

(d) payment to NS Power of all DT charges applicable to the LRS's RtR Customer(s);

(e) adhering to the Credit Assurance requirements of NS Power as described in Section 18;

(f) obtaining and providing the RtR Customer's written consent, in a form acceptable to NS Power, in support of any transaction requests submitted to NS Power on behalf of the RtR Customer;

(g) obtaining any consents from the RtR Customer required by NS Power with respect to the use or disclosure of Customer Information;

(h) providing NS Power, in a timely manner, with up-to-date RtR Customer Information for all RtR Customers served by the LRS;

(i) acting as the point of contact for RtR Customers served by the LRS on all matters related to billing and collection of accounts;

(j) ensuring that the LRS's RtR Customers are aware of the terms and conditions of any NS Power tariff to which the LRS subscribes that may affect the RtR Customer;

(k) ensuring that the RtR Customers are aware of their responsibilities under the NS Power Regulations; and

(l) notifying NS Power of the discontinuance of service to any RtR Customer by the LRS.

8.2 The LRS shall adhere to and comply with the requirements of the applicable NS Power Regulations identified herein.

8.3 The LRS shall adhere to and comply with Board Electricity Retailers Regulations (Nova Scotia) and the Code of Conduct for the sale of Renewable Low-Impact Electricity Sales in Nova Scotia.

LRS ARRANGEMENTS WITH RTR CUSTOMERS

9.1 The LRS shall enter into a written contract with each of its RtR Customer(s) with respect to any sale of renewable low-impact electricity by the LRS to such RtR Customer ("RtR Customer Contract").

9.2 NS Power shall not be responsible for monitoring, reviewing or enforcing the RtR Customer Contract(s).

9.3 NS Power shall not be liable for any loss, damages, cost, injury, expense or other liability, whether direct, indirect, consequential or special in nature, howsoever caused, as a result of any breach of an RtR Customer Contract by either the LRS or the RtR Customer.

9.4 The LRS shall ensure that each RtR Customer Contract contains a statement to the effect that NS Power shall not be liable in damages to the RtR Customer in respect of any breach of the RtR Customer Contract by the LRS or for any delay, interruption or other partial or complete failure in the supply of electricity to the RtR Customer.

9.5 The LRS shall defend, protect, release, indemnify, keep indemnified and shall hold NS Power harmless from and against and be liable to NS Power for any and all damages, losses, claims or expenses which NS Power may at any time sustain or incur to the extent arising, directly or indirectly, from (i) any acts or omissions of the LRS or any agent, employee, of the LRS or person acting on behalf of any of them; and (b) any claims by a third party, including an RtR Customer, arising out of a breach of the RtR Customer Contract.

9.6 The LRS shall ensure that each RtR Customer Contract contains an acknowledgement from the RtR Customer that the RtR Customer will revert to NS Power's Bundled Service upon discontinuance of LRS Tariffed Service and the termination of the LRS Participation Agreement unless an RtR Customer Transaction Request Application has submitted by an alternate LRS on behalf of the RtR Customer to NS Power nominating an alternate LRS.

9.7 Any assignment, sale or transfer of an RtR Customer Contract by an LRS shall not be effective until the LRS has submitted and NS Power has accepted an RtR Customer Transaction Request Application for the applicable RtR Customer.

NS POWER RESPONSIBILITIES

10.1 NS Power shall be responsible for:

(a) processing all RtR Customer Transaction Request Applications submitted by an LRS in accordance with Section 11;

(b) provision of the services delivered under the OATT, Energy Balancing Service Tariff, Standby Service Tariff and the Renewable to Retail Market Transition Tariff to the LRS;

(c) provision of Distribution System Access to applicable RtR Customers;

(d) providing metering services;

(e) performing Load Settlement for each LRS;

(f) issuing invoices to the LRS;

(g) maintaining Customer Information for all customer sites as necessary to perform Load Settlement;

(h) maintaining Customer Information as it is supplied and updated by the RtR Customer; and

(i) acting as the point of contact for RtR Customers for matters related to the provision of Distribution Access Service.

10.2 Interruption of LRS Tariffed Services

10.2.1 NS Power shall have the right to suspend or interrupt the delivery of Distribution System Access or any or all of the LRS Tariffed Services for the purpose of safeguarding life or property, for making repairs, changes, renewals, improvements or replacements to the Transmission System or Distribution System provided NS Power shall make Reasonable Efforts to ensure all such interruptions or suspensions are of a minimum duration consistent with the exigencies of the case. Further, provided, however, any such interruption or suspensions shall not release the LRS from its obligation to pay all charges pursuant to any NS Power tariffs applicable to the LRS Tariffed Services, or otherwise owing to NS Power under the LRS T&Cs, including the DT Charges, during the period of any such suspensions.

10.3 Limitation of Liability

10.3.1 Notwithstanding any other provision herein, NS Power shall not be liable for any claim, loss, cost, liability, actions, judgment, suit, proceeding, expense, disbursement or damage whatsoever arising, either directly or indirectly, whether in contract or tort (including negligence) or otherwise, from any interruptions, diversions, curtailments, suspension or other procedures necessary to maintain the efficient and effective operation of either the Distribution System or the Transmission System. This would include Distribution System Access and any or all LRS Tariff Services provided by NS Power to the LRS.

10.3.2 Notwithstanding any other provision herein, and in addition to Sections 10.3.1, NS Power shall not be liable for any claims, losses, costs, liabilities, obligations, actions, judgments, suits, expenses, disbursements or damages of an LRS or its directors, officers or employees whatsoever, whether in contract or in tort (including negligence) or any other legal theory, arising, directly or indirectly, out of any act or omission of NS Power in the exercise of any power or obligation under the LRS T&Cs or any applicable tariff, including the Distribution Tariff, the Energy Balancing Service Tariff, the Standby Service Tariff, the OATT and the Renewable to Retail Transition, except to the extent such claim, loss or damages results from the gross negligence or willful misconduct of NS Power.

10.3.3 For the purposes of Section 10.3.2, an act or omission of NS Power effected in compliance with the LRS T&Cs or the applicable tariffs shall be deemed not to constitute willful misconduct or a negligent act or omission.

10.3.4 Notwithstanding any other provision herein or applicable law to the contrary, NS Power shall not be liable to the LRS for:

(a) any indirect or consequential loss or incidental or special damages, including, without limitation, any punitive or aggravated damages;

(b) any loss of profit, loss of contract, loss of opportunity or loss of goodwill; or

(c) damages for loss of use,

arising, directly or indirectly, with the performance or delivery of the LRS Tariff Services or Distribution System Access, including, but not limited, to interruptions, diversions, curtailments or suspensions of any of the LRS Tariffed Services or Distribution System Access or from any acts or omissions of its employees or agents, and whether arising in contract, indemnity, tort (including negligence) or any other legal theory.

RTR CUSTOMER TRANSACTIONS

11.1 Prior to enrollment of a new RtR Customer or modifying the enrollment of an existing RtR Customer, the LRS shall complete and submit to NS Power an RtR Customer Transaction Request Application duly executed by the LRS and the applicant customer. NS Power will review the RtR Customer Transaction Request Application and notify the LRS upon its acceptance or rejection. For certainty, completed RtR Customer Transaction Request Applications duly executed by the LRS and the applicable customer shall be required for each of the following categories of transactions:

(a) A request to enroll a current NS Power Bundled Service customer as an RtR Customer of the LRS;

(b) A request to enroll a Retail Customer, that is not currently an NS Power Bundled Service customer, as an RtR Customer of the LRS;

(c) A request for return of an LRS's RtR Customer to NS Power's Bundled Service;

(d) A request, initiated by the LRS of record, to transfer an existing RtR Customer from the current LRS to another LRS (Assignee), subject to the written authorization of the Assignee;

(e) A request to obtain Customer Information from NS Power;

(f) Notification to NS Power of updated Customer Information; and

(g) Such other service request types as determined by NS Power.

11.2 The LRS shall provide complete Customer Information with each application for RtR Customer enrollment or transfer.

11.3 NS Power reserves the right to refuse to accept an RtR Customer Transaction Request Application for any Retail Customer who has outstanding debt payable to NS Power in relation to previous electric service.

11.4 NS Power reserves the right to refuse to accept an RtR Customer Transaction Request Application for any Retail Customer whose premises is physically connected to the Transmission System until the Retail Customer has executed a separate operating agreement with NS Power in a form satisfactory to NS Power. Such an operating agreement will address operational issues including, but not limited to the following: descriptions of facilities and delivery points, characteristics of supply, metering, load balance, harmonics, right of way, right of access and general obligations of both the transmission-connected Retail Customer and NS Power.

11.5 RtR Customer Transaction Request Applications will be processed based on the order in which they are received by NS Power.

11.6 Upon acceptance of an RtR Customer Transaction Request Application, NS Power will notify the LRS and record the LRS as the LRS of record for the particular RtR Customer Premises. If an RtR Customer Transaction Request Application is rejected, NS Power will provide the LRS with the reason(s) for the rejection.

11.7 All outstanding indebtedness of the RtR Customer to NS Power in respect of any NS Power electrical service supplied to the RtR Customer must be paid in full before NS

Power can accept the enrollment of the RtR Customer with the LRS or the transfer of the RtR Customer to an alternate LRS.

11.7 Following acceptance of the Customer Transaction Request Application by NS Power, the RtR Customer transactions will be effective for the period following the next meter reading for the RtR Customer.

11.8 NS Power shall ensure that each distribution connected RtR Customer is provided with a copy of the Distribution Tariff.

LRS RTR CUSTOMER INFORMATION INQUIRIES

12.1 Provision of NS Power Customer Information to LRS

1.1.1 Subject to receipt of the consent of the Retail Customer, NS Power will provide Customer Information to an LRS with which it has an executed LRS Participation Agreement.

1.1.2 An LRS with a fully executed LRS Participation Agreement with NS Power may request Customer Information prior to the RtR Customer subscribing with the LRS provided the RtR Customer has consented in writing to the disclosure of such information to the LRS.

1.1.3 The LRS shall initiate this request by submitting an RtR Customer Transaction Request Application.

12.2 Provision of RtR Customer Information between the LRS and NS Power

12.2.1 The LRS shall notify NS Power promptly of any changes to the Customer Information.

12.2.2 Subject to any confidentiality, NS Power and the LRS shall each supply to the other data, materials or other information that may be reasonably required in connection with the performance of its obligations under the LRS T&Cs.

METERING

13.1 Provision and Ownership

1.1.4 NS Power will install and seal all revenue class meters for the purpose of measuring the output of the LRS's generation resources and the RtR Customer's load as necessary for application of the applicable NS Power tariffs. Meter data from such meters will be used for Load Settlement for the purpose of determining the charges for the LRS Tariffed Services. The meters will also be used to determine charges for Distribution System Access under the Distribution Tariff.

1.1.5 Interval meters with remote polling capability shall be installed for all RtR Customers. NS Power will charge the costs of the supply and installation of metering devices and communications equipment and services which are incremental to the metering requirements applicable to NS Power's Bundled Service. Metering for LRS generation resources (whether owned or contracted) will be provided in accordance with the applicable Generator Interconnection Agreement.

1.1.6 Meters and associated revenue metering equipment shall remain the property of NS Power.

1.1.7 All revenue metering equipment installations shall meet the Electricity and Gas Inspection Act regulations requirements in effect at the time.

1.1.8 NS Power Regulations with respect to metering shall apply to metering of RtR Customer loads for the purpose of billing the LRS for LRS Tariffed Services.

1.1.9 Any LRS instituting connection of a generation resource to RtR Customer load that is behind the main NS Power revenue meter will:

(a) install secondary revenue class metering with remote polling capability at each applicable RtR Customer Premises to a standard satisfactory to NS Power ("Secondary Metering"); and

(b) provide NS Power access to read and test such metering as well as electronic access for the purpose of polling the meter data.

Data from Secondary Metering will be used in settlement of the LRS Tariffed Services, and all applicable DT Charges due from the LRS to NS Power.

13.2 Meter Reading

13.2.1 NS Power shall use Reasonable Efforts to obtain a meter reading for each RtR Customer Premises in accordance with NS Power's meter reading cycle. If NS Power is unable to obtain a meter reading, the amount of power and energy used by the RtR Customer in the Billing Period shall be estimated by NS Power.

13.2.2. At the request of the LRS, NS Power shall use Reasonable Efforts to obtain an actual meter reading at a time other than the regularly scheduled meter reading. NS Power will charge the LRS for additional meter reading expense in accordance with NS Power Regulation 7.1 - Schedule of Charges.

13.2.3 NS Power Regulations with respect to meter reading shall apply to metering of RtR Customer loads for the purpose of billing the LRS for LRS Tariffed Services and DT Charges.

BILLING AND SETTLEMENT

14.1 Billing of RtR Customers

1.1.10 In order that the LRS may bill its RtR Customers for the sale of renewable low-impact electricity, NS Power will provide the LRS with the metering data applicable to each of the LRS's RtR Customers.

14.1.2 All DT Charges will be calculated by NS Power using the RtR Customer's meter readings and the Distribution Tariff Rate Schedule applicable to the RtR Customer's rate class.

14.1.3 The LRS shall invoice the LRS's RtR Customer for the DT Charges and consolidate such charges and fees on the LRS's invoice to the RtR Customer. The DT Charges shall not be marked-up, added to, aggregated, bundled, unbundled, or otherwise altered by the LRS. DT Charges related to special customer services will be itemized and provide the total amount of the charge.

14.1.4 NS Power may, at its discretion, include fees for any special customer services provided at the LRS's or the RtR Customer's request, pursuant to NS Power Regulation 7.1 - Schedule of Charges.

14.2 NS Power Settlement and Billing to LRS for Aggregated Charges

14.2.1 Charges for LRS Tariffed Services provided to the LRS shall be based on the aggregated RtR Customer load and the LRS aggregate generation (whether owned or contracted). The charge determinant shall be based on the aggregate energy and peak hourly aggregate demand of an LRS's RtR Customer loads in conjunction with the hourly aggregate energy of the LRS generation (whether owned or contracted). NS Power will invoice for each of the services provided to the LRS under the Energy Balancing Service Tariff, Standby Service Tariff and the Renewable to Retail Transition Tariff in accordance with the rates, terms and conditions set out in those tariffs.

14.2.2 NS Power will invoice the LRS for Transmission Services and associated Ancillary Services in accordance with the rates, terms, riders and conditions set out in the OATT and in accordance with the Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules and Procedures.

14.3 Settlement Methodology for Determining the Aggregated Charges

14.3.1 To determine the charges described in Section 14.2, NS Power shall determine the aggregate load for each hour in the Billing Period for the total of all RtR Customers of the LRS, and the aggregate output for each hour in the Billing Period of all RtR generation serving the LRS.

14.3.2 To determine the aggregated LRS hourly load and generation profiles using interval meters, NS Power will aggregate the individual meter interval readings for each hour in the Billing Period. The aggregated hourly load and generation profiles will be used in the settlement calculations.

14.4 Determination of RtR Load Requirement at Transmission Voltage

14.4.1 Meter readings for distribution-connected RtR Customer loads will be adjusted for distribution losses using established average annual rate class losses for the purpose of

Load Settlement for each of the LRS Tariffed Services which are applicable at the transmission voltage level.

14.5 NS Power Billing Procedure

14.5.1 Within a reasonable time after the first day of each month, NS Power shall submit an invoice to the LRS for the charges for all LRS Tariffed Services received by the LRS during the preceding month. Unless NS Power directs otherwise in writing, NS Power will also invoice the LRS for the DT Charges.

14.5.2 LRS agrees to pay NS Power in full for the DT Charges in the manner set out herein and the LRS shall have the right to seek reimbursement from its applicable RtR Customers for such DT Charges.

14.5.3 The LRS shall be liable to NS Power for payment of the full amount of any and all DT Charges applicable to the LRS's RtR Customers invoiced by NS Power, notwithstanding the ability of the LRS to obtain payment of such amounts from its RtR Customers. Non-payment of the DT Charges by an LRS's RtR Customer shall not constitute a valid defence for non-payment by the LRS to NS Power.

14.5.4 The LRS shall consolidate the DT Charges on the LRS's invoice to the RtR Customer; provided, however, the DT Charges shall not be marked-up, added to, aggregated, bundled, unbundled, or otherwise altered by the LRS.

14.5.5 The format of the LRS's invoice/bill, in terms of the incorporation of any DT Charges, shall be in a form deemed acceptable to NS Power.

14.5.6 Unless, NS Power directs otherwise in writing, the LRS shall be responsible for the collection of all DT Charges owing by its RtR Customers. LRS shall at all times indemnify, defend, and save NS Power harmless from and against any and all damages, losses, claims, costs, liabilities, actions, judgments, suits, proceedings, expenses or disbursement whatsoever arising out of, either directly or indirectly, whether in contract or tort (including negligence) or otherwise, the collection of DT Charges by the LRS, its employees or its agents.

14.5.7 All invoices issued by NS Power, including an invoice for the DT Charges, shall be paid by the LRS to NS Power in full within twenty (20) Calendar Days of the billing date. All payments shall be made in immediately available funds payable to NS Power. Invoiced amounts which are not paid by the LRS within twenty (20) Calendar Days after the billing date shall be subject to an interest charge as set forth in Section 14.6.

14.5.8 Each invoice shall state the period to which the invoice applies and describe the services provided. The amount due within the twenty (20) day period set out in Section 14.5.7 and the effective date of the interest charge shall be clearly shown on the invoice. Where practicable, NS Power will address credits and payment obligations due under any tariff on the same invoice through netting, including interest payments or credits.

14.5.9 Unless otherwise expressly stated, all references in the tariffs, a settlement statement or an invoice to a monetary amount shall be expressed in Canadian dollars.

14.6 Interest on Unpaid Balances

14.6.1 Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified in NS Power Regulation 5.4. When payments are made by mail, invoices shall be considered as paid on time if the envelope is postmarked on or before the last date for net payment.

DEFAULT FOR NON-PAYMENT

1.1.11 In the event a Licenced Retail Supplier fails, for any reason other than a billing dispute as described below, to make payment to NS Power on or before the due date as described in Section 14.5.7, and such failure of payment is not corrected within thirty (30) Calendar Days after NS Power notifies the LRS to cure such failure, a default by the LRS shall be deemed to exist. Upon the occurrence of such a default by the LRS, NS Power may discontinue the LRS Tariffed Services and terminate the LRS Participation Agreement without any liability or responsibility whatsoever, except for obligations arising prior to the date of termination.

1.1.12 In the event of a billing dispute between NS Power and the LRS, NS Power shall continue to provide LRS Tariffed Services as long as the LRS (i) gives written notice of the dispute to NS Power on or before the due date for the payment, detailing the amount and reasons for the dispute; (ii) continues to make all payments not in dispute, and (iii) prior to the due date for payment pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Licenced Retail Supplier fails to meet these three requirements for continuation of service, then NS Power may provide notice to the Licenced Retail Supplier of its intention to discontinue the LRS Tariffed Service and terminate the LRS Participation Agreement in thirty (30) Calendar Days.

EVENTS OF DEFAULT

1.2 In addition to its rights of discontinuation and termination under Section 15, NS Power may, without prejudice to any other rights or remedies it may have, immediately discontinue the LRS Tariffed Services and terminate the LRS Participation Agreement upon notice in writing to the LRS:

(a) if he LRS's Retail Supplier Licence has been cancelled or otherwise revoked;

(b) if the LRS has failed to meet or maintain the Credit Assurance requirements set out in Section 18;

(c) if the LRS is disqualified (or no longer qualifies) as a Market Participant within the NS Power operating area;

(d) if the LRS fails to adhere to the NS Power Regulations identified herein as applicable to the LRS following the expiration of any applicable cure period set out in the NS Power Regulations;

(e) if the LRS defaults in the performance of any of its obligations under the LRS T&Cs (other than those set out in Section 15 and Section 16.1(a) to (d) above) and fails to cure such default within twenty (20) Calendar Days of notice of such default by NS Power; or

(f) in the event of any liquidation, winding up or bankruptcy of the LRS, whether voluntary or compulsory, or any composition with creditors or scheme of arrangement.

16.2 Upon discontinuance of LRS Tariffed Service and the termination of the LRS Participation Agreement, and in the absence of an RtR Customer Transaction Request Application accepted by NS Power requesting the RtR Customer be assigned to an alternate LRS, the provision of Bundled Service to the affected RtR Customers(s) shall be assumed by NS Power as the default supplier, in accordance with NS Power's Regulations.

16.3 In the event an RtR Customer breaches, defaults upon or otherwise fails to adhere to NS Power Regulations ("Defaulting RtR Customer"), NS Power shall have the right, without liability or penalty, to immediately terminate or suspend any service to the Defaulting RtR Customer upon notice in writing to the LRS.

DISCONTINUANCE OF SERVICE TO RTR CUSTOMER BY THE LRS

17.1 To discontinue LRS Tariffed Services to an RtR Customer Premises, an LRS shall complete and provide to NS Power, an RtR Customer Transaction Request Application, in accordance with Section 11.

17.2 The LRS shall provide the RtR Customer with advance notice of any request to discontinue the provision of service to that RtR Customer, and be responsible to the RtR Customer for consequences of any such discontinuance. NS Power will not be held liable for any RtR Customer disputes with the LRS regarding the discontinuance of LRS Tariffed Services to an RtR Customer Premises.

17.3 The LRS Tariffed Services shall continue in effect and the LRS shall remain responsible for payment of the LRS Tariffed Services until the next meter reading is obtained. If NS Power has received and accepted an RtR Customer Transaction Request Application from an alternate LRS ("Assignee") for an RtR Customer, that Assignee will be appointed as the new LRS of record for the RtR Customer, otherwise the RtR Customer will be returned to NS Power's Bundled Service.

17.4 NS Power reserves the right to refuse an RtR Customer Transaction Request Application from any Retail Customer who has outstanding debt payable to NS Power in relation to previous electric service. NS Power Regulations including, but not limited to application for service, connection and disconnection of service, payment of accounts and deposits will apply to the RtR Customer's return to NS Power's Bundled Service.

CREDIT ASSURANCE

18.1 An LRS must provide, in advance, Credit Assurance as security for the payment and performance of the LRS's obligations to NS Power, including payment for the LRS Tariffed Services and payment of the DT Charges, regardless of payment history, before NS Power provides any of the LRS Tariffed Services to the LRS.

18.2 On any Business Day (but no more frequently than once per calendar month), NS Power will provide the LRS with written notice requesting Credit Assurance in an amount determined by NS Power and based upon an amount equal to two hundred percent (200%) of the forecasted payment for the LRS Tariffed Services and DT Charges combined (rounded upwards for any fractional amount to the nearest $1000). Upon receipt of such notice the LRS shall have three (3) Business Days to provide such Credit Assurance to NS Power. In the event that the LRS fails to provide such Credit Assurance acceptable to NS Power within three (3) Business Days of such request, then a default will be deemed to have occurred in accordance with Section 16.1(b).

18.3 NS Power shall be entitled to draw upon or otherwise realize upon the Credit Assurance in the event of any default pursuant to Section 15 or Section 16 herein and apply such funds against the LRS's payment obligations until such time as all of the LRS's obligations have been satisfied. If the Credit Assurance is insufficient to satisfy the LRS' payment obligations, the LRS shall remain liable to NS Power for the balance of the amount owing. If NS Power draws upon or otherwise realizes upon the Credit Assurance as permitted hereunder, then the LRS shall provide additional or replacement Credit Assurance which is sufficient to maintain the Credit Assurance in an amount determined by NS Power as set out herein.

18.4 Costs of a Letter of Credit shall be the responsibility of the LRS and not NS Power. To the extent that a Letter of Credit introduces a lag time and there are additional costs to NS Power, these costs will be paid by the LRS.

18.5 To the extent the LRS delivers Credit Assurance hereunder in the form of cash to NS Power, the LRS shall be deemed to have pledged and assigned to NS Power, as security for the payment and performance of such LRS's obligations owing to NS Power, a present and continuing security interest in, and lien on (and right of setoff against), all such cash collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of NS Power. The LRS shall also take such action as NS Power reasonably requires in order to perfect NS Power’s security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from the liquidation thereof.

18.6 All cash held by NS Power as Credit Assurance shall be held without interest.

FORCE MAJEURE AND INDEMNIFICATION

19.1 Force Majeure

1.2.1 Force Majeure is any cause beyond the reasonable control of NS Power including, without limiting the generality of the foregoing, an act of God, failure of facilities or equipment, flood, earthquake, storm, nuclear disaster, lightning, fire, epidemic, war, riot, civil disturbance, labour trouble, strike, sabotage, terrorism and restraint by court or public authority which by exercise of Good Utility Practice NS Power could not be expected to reasonably avoid. If NS Power is rendered unable to fulfill any obligations by reason of Force Majeure, it shall be excused from performing to the extent it is prevented from so doing but it shall exercise Good Utility Practice to correct such inability with all reasonable dispatch, and it shall not be liable for any injury, damage or loss resulting from such inability. However, settlement of strikes and labour disturbances shall be wholly within the discretion of NS Power.

19.2 Indemnity by LRS

19.2.1 The LRS shall at all times indemnify, defend, and save NS Power harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, legal fees, and all other obligations by or to third parties, including, without limitation the RtR Customer, arising out of or resulting from NS Power's performance of its obligations on behalf of the LRS in respect of the LRS Tariffed Services on behalf of the LRS, except to the extent such claim, loss or damages results from the gross negligence or willful misconduct of NS Power.

APPENDIX A

RTR CUSTOMER TRANSACTION REQUEST APPLICATION FORM

[**TO BE DEVELOPED DURING IMPLEMENTATION**]

APPENDIX B
LRS PARTICPATION AGREEMENT

LRS Participation Agreement (“Agreement”)

THIS LRS PARTICIPATION AGREEMENT (“Agreement”) dated this ____ day of _______________, 20__ (“Effective Date”)

BETWEEN:

[Name of Licenced Retail Supplier],

(hereinafter referred to as the “Licenced Retail Supplier” or “LRS”)

-and-

Nova Scotia Power Incorporated, a body corporate organized under the laws of the Province of Nova Scotia.

(hereinafter referred to as “NS Power”)

(individually a “Party”, together the “Parties”)

RECITALS:

A. The LRS has been issued a valid Retail Supplier Licence by the Board under the *Electricity Act* (Nova Scotia) dated **[insert date]** and bearing licence number **[insert licence number]**; and

B. The LRS wishes to sell renewable low-impact electricity, generated within the Province, to RtR Customers in accordance with the Act and the regulations made thereunder; and

C. The LRS Terms and Conditions approved by the Board are to have the effect of a contract between LRS and NS Power by virtue of the execution of an LRS Participation Agreement of which the LRS Terms and Conditions are deemed to form a part;

D. The LRS and NS Power wish to enter into this LRS Participation Agreement to satisfy the condition contained in the LRS Terms and Conditions that an LRS Participation Agreement be executed in order for the LRS to be eligible for LRS Tariffed Services from NS Power.

NOW THEREFORE, in consideration of the mutual covenants in this Agreement and of other good and valuable consideration, the receipt and adequacy of which is hereby acknowledged, the Parties agree as follows:

ARTICLE 1

LRS PARTICIPATION TERMS AND CONDITIONS

1.1 **Paramountcy:** In the event of any inconsistency between the terms of this Agreement and the LRS Terms and Conditions, the LRS Terms and Conditions shall prevail to the extent of the inconsistency. The LRS Terms and Conditions are published on NS Power's website at: http//xxxx.xx**.[NTD Insert when address is known]**

1.2 **Definitions:** All capitalized terms utilized in this Agreement shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

1.3 **Recitals:** The recitals shall form an integral part of this Agreement.

1.4 **Headings:** The division of this Agreement into articles and sections and the insertion of headings are for convenience of reference only and shall not affect the interpretation of this Agreement, nor shall they be construed as indicating that all of the provisions of this Agreement relating to any particular topic are to be found in any particular article, section, subsection, clause or provision.

ARTICLE 2

COMPLIANCE WITH LRS TERMS AND CONDITIONS

2.1 This Agreement is subject to the Board approved LRS Terms and Conditions, as amended from time to time. The LRS Terms and Conditions are deemed to form a part of this Agreement and is hereby incorporated into this Agreement. For certainty, any reference to "Agreement" includes the LRS Terms and Conditions.

2.2 Each Party acknowledges that it has received a copy of the LRS Terms and Conditions, has reviewed and understands the LRS Terms and Conditions and agrees to be bound by the LRS Terms and Conditions and any amendments thereto. Each Party agrees to comply with the LRS Terms and Conditions.

ARTICLE 3

QUALIFICATION FOR LRS TARIFFED SERVICES

3.1 The LRS warrants and agrees that all conditions and prerequisites for the LRS to be eligible for LRS Tariffed Services as set out in the Act and the LRS Terms and Conditions have been met as of the date of this Agreement and will continue to be met at all times during the term of this Agreement.

3.2 The LRS acknowledges and agrees that subscription by LRS to each of the Energy Balancing Service Tariff, Standby Service Tariff, Renewable to Retail Market Transition Tariff and the Open Access Transmission Tariff by the LRS is compulsory. For certainty, the LRS shall not be entitled to receive one or more of the individual LRS Tariffed Services without agreeing to accept and receive all of the LRS Tariffed Services.

ARTICLE 4

CREDIT ASSURANCE REQUIREMENTS

4.1 The LRS shall provide NS Power with, and shall maintain Credit Assurance for the performance of its obligations in accordance with Article 18 of the LRS Terms and Conditions.

ARTICLE 5

DEFAULTS AND REMEDIES

5.1 The LRS acknowledges the rights and obligations of NS Power and the LRS should either party default in the performance of its obligations under this Agreement, as set out in the LRS Terms and Conditions.

ARTICLE 6

REPRESENTATIONS AND WARRANTIES

6.1 **Representations and Warranties of LRS:** The LRS hereby represents and warrants as follows to NS Power and acknowledges and confirms that NS Power is relying on such representations and warranties without independent inquiry:

(a) it is a [form of business organization] duly [incorporated/formed/registered] and existing under the laws of [location];

(b) it has all the necessary corporate power to enter into and perform its obligations under this Agreement;

(c) the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate action;

(d) the individual(s) executing this Agreement, and any document in connection herewith, on behalf of the LRS have been duly authorized to execute this Agreement and have the full power and authority to bind the LRS;

(e) this Agreement constitutes a legal and binding obligation on the LRS, enforceable against the LRS in accordance with its terms; and

(f) it holds all permits, licences and other authorizations that may be necessary to enable it to carry on the business and perform the functions and obligations of an LRS as described in the Act and in this Agreement.

6.2 **Representations and Warranties of NS Power:** NS Power hereby represents and warrants as follows to the LRS and acknowledges and confirms that the LRS is relying on such representations and warranties without independent inquiry:

(a) it is a body corporate duly organized and existing under the laws of the Province of Nova Scotia;

(b) it has all the necessary corporate power to enter into and perform its obligations under this Agreement;

(c) the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate action;

(d) the individual(s) executing this Agreement, and any document in connection herewith, on behalf of NS Power have been duly authorized to execute this Agreement and have the full power and authority to bind NS Power; and

(e) this Agreement constitutes a legal and binding obligation on NS Power, enforceable against NS Power in accordance with its terms.

6.3 **Notification:** Each Party shall promptly notify the other Party of any circumstance that does or may result in any of the representations and warranties of such party as set forth in this Agreement or the LRS Terms and Conditions becoming untrue or inaccurate during the term of this Agreement. The LRS shall also promptly notify NS Power of any events, circumstances or conditions that has, had or could have the effect of resulting in the LRS no longer being qualified as an LRS.

ARTICLE 7

MISCELLANEOUS

7.1 **Amendment:** No amendment of this Agreement shall be effective unless made in writing and signed by the Parties.

7.2 **Assignment:** The LRS may not assign or transfer, whether absolutely, by way of security or otherwise, all or any part of its rights or obligations under this Agreement without the prior written consent of NS Power. For certainty, NS Power shall not consent to an assignment of this Agreement by the LRS where the Board has not permitted the transfer or assignment of the LRS's Retailer Supplier Licence to the assignee or the assignee does not otherwise holds a valid Retail Supplier Licence issued by the Board.

7.3 **Successors and Assigns:** This Agreement shall enure to the benefit of, and be binding on, the Parties and their respective heirs, administrators, executors, successors and permitted assigns.

7.4 **Further Assurances:** Each Party shall promptly execute and deliver or cause to be executed and delivered all further documents in connection with this Agreement that the other Party may reasonably require for the purposes of giving effect to this Agreement.

7.5 **Confidentiality Obligations:** Notwithstanding any term or condition of this Agreement, if the Agreement is terminated, the LRS shall remain subject to any confidentiality obligations with respect to all Confidential Information obtained by or provided to the LRS while the LRS was a Party to the Agreement.

7.6 **Ongoing Obligations:** If the Agreement is terminated, the LRS shall remain subject to and liable for all of its obligations and liabilities under this Agreement that were incurred or arose prior to the date of termination, regardless of the date on which any claim relating thereto may be made.

7.7 **Waiver:** A waiver of any default, breach or non-compliance under this Agreement is not effective unless in writing and signed by the Party to be bound by the waiver. No waiver will be inferred or implied by any failure to act or by the delay in acting by a Party in respect of any default, breach or non-observance or by anything done or omitted to be done by the other Party. The waiver by a Party of any default, breach or non-compliance under this Agreement shall not operate as a waiver of that Party's rights under this Agreement in respect of any continuing or subsequent default, breach or non-observance (whether of the same or any other nature).

7.8 **Severability:** Any provision of this Agreement that is invalid or unenforceable in any jurisdiction shall, as to that jurisdiction, be ineffective to the extent of that invalidity or unenforceability and shall be deemed severed from the remainder of this Agreement, all without affecting the validity or enforceability of the remaining provisions of this Agreement or affecting the validity or enforceability of such provision in any other jurisdiction.

7.9 **Notices:** Any notice, demand, consent, request or other communication required or permitted to be given or made under this Agreement shall be given in writing and must be given by personal delivery, registered mail or facsimile transmittal as follows:

To NS Power: Nova Scotia Power Inc.
Attention: Corporate Secretary
Address: 1223 Lower Water Street
Halifax, NS B3J 3S8
Facsimile: (902) 428-6171

To LRS: LRS:
Address
Attention:
Facsimile:

or to such address, facsimile number, or individual as may be agreed between the Parties in writing.

7.10 **Governing Law:** This Agreement shall be governed by and construed in accordance with the laws of the Province of Nova Scotia and the federal laws of Canada applicable therein.

7.11 **Survival:** Notwithstanding any provision to the contrary and for greater certainty, Article 7 of this Agreement and Articles 3.2, 8, 9, 10.2, 10.3 14.5, 18 and 19.2 of the LRS Terms and Conditions shall survive any termination of this Agreement without limit as to time.

7.13 **Counterparts:** This Agreement may be executed by the Parties hereto in counterparts, each of which when so executed and delivered shall be deemed to be an original and when taken together shall be deemed to be one and the same instrument. The electronic delivery, including, without limitation, by email or facsimile transmission, of any signed original of this Agreement shall be the same as the delivery of an original.

IN WITNESS WHEREOF the Parties have, by their duly appointed and authorized representatives, executed this Agreement effective as of the Effective Date.

[INSERT NAME OF LICENCED RETAIL SUPPLIER]	**NOVA SCOTIA POWER INCORPORATED**
Date:______________________________	Date: ______________________________
Signature: _________________________	Signature: _________________________
Name: _____________________________	Name: _____________________________
Title: ______________________________	Title: ______________________________
	Date: ______________________________
	Signature: _________________________
	Name: _____________________________
	Title: ______________________________

ENERGY BALANCING SERVICE TARIFF
Renewable to Retail

ENERGY BALANCING SERVICE

The Energy Balancing Service is a supplemental generation service provided to Licenced Retail Suppliers (LRS) in respect of the Licenced Retail Supplier's RtR Customers utilizing the production from renewable low-impact generators. The service consists of delivery of complementary energy to RtR Customers and reception of surplus generation from qualifying generators. The service is required to be taken in conjunction with Standby Service under the Standby Service Tariff so that the reliability of service to RtR Customers is equivalent to that provided under Bundled Service. For the purposes of this Energy Balancing Service Tariff, hourly LRS load in excess of generation is defined as top-up energy and hourly generation in excess of LRS load is defined as spill energy.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Energy Balancing Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Energy Balancing Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Energy Balancing Service Tariff shall also take service under the OATT, the Standby Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Energy Balancing Service Tariff is based on metered energy quantities, and is independent of the LRS's forecasts. OATT Schedule 4 is not applicable, but the Generation Forecasting Service under Schedule 4A of the OATT is applicable.

(3) The hourly top-up and spill quantities are determined at the delivery point from the transmission system. The hourly top-up quantity equals the excess in each hour, if positive, of the LRS's aggregate customer load adjusted by the addition of distribution losses over the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission losses. The hourly spill quantity equals the excess in each hour, if positive, of the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of

ENERGY BALANCING SERVICE TARIFF
Renewable to Retail

transmission losses over its aggregate customer load adjusted by the addition of distribution losses. The aggregate hourly load quantities are determined in accordance with the applicable provisions in the LRS Terms and Conditions.

(4) To qualify for this service, the LRS must ensure that the imbalance between low impact renewable generation and energy consumption over the established compliance period conforms to Section 10 of the Board Electricity Retailers Regulations (Nova Scotia) enacted under the Act.

(5) Maximum Spill Capacity must be approved by NS Power prior to commencement of service and will be limited to a level agreed as being required to provide the contracted annual amount of participating LRS energy. Spill capacity will be reviewed annually and will include the LRS' proposal to mitigate it on a going forward basis. If NS Power is not satisfied with the LRS' proposal, it may impose a limit on hourly production of the LRS's generation portfolio.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS's subscribed} * 12}$$

This charge will be $1,053.03 per month.

ENERGY CHARGE

Energy charge for top-up service is made up of the following two components:

1. Annually adjusted fuel cost component based on NS Power's incremental cost of serving the LRS's forecasted incremental top-up load.

2. Fixed cost adder reflective of fixed cost energy-related generation costs.

Energy Charge Components	**Cents per kWh**
Fuel Cost	6.650
Fixed Cost Adder	3.309
Total	9.959

The charge is applicable to top-up energy consumed in each hour.

ENERGY BALANCING SERVICE TARIFF
Renewable to Retail

ENERGY CREDIT

The Energy Credit for spill service is set annually, on a calendar year basis, and is made up of two components:

1. Monthly compensation for spill energy delivered to NS Power and applicable in each hour of 5.27 cents per kilowatt hour

2. The year-end refund to NS Power on monthly compensation in respect of annual excess spill energy above annual consumption of the LRS's RtR Customers recognized without discount as set out in the following table:

Annual Excess Spill Quantity in the range	Discount Applied	Cents per kWh
from 0% to 10% of Annual LRS Load	0%	5.270
greater than 10% up to 20% of Annual LRS Load	10%	4.743
greater than 20% up to 30% of Annual LRS Load	25%	3.953
greater than 30% of Annual LRS Load	50%	2.635

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS's RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the

following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Energy Balancing Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Utility and Review Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Energy Balancing Service Tariff, the Standby Service Tariff or the Renewable to Retail Market Transition Tariff.

Energy Balancing Service: Administration Charge Calculations

Assumptions
(1) One Full Time Equivalent is sufficient to provide admin service in the initial market opening
(2) Assume 4 Licensed Service Providers. Note that this approach aligns with that used under the current Backup/Top-up Tariff.
(3) Admin costs to be shared equally between Energy Balancing and Standby Services

Full Time Equivalent (FTE) Cost

Salary		58,098
Fringe Benefits	16.0%	$9,296
Salary (including fringe benefits)		$67,394
Administrative Overhead	50%	$33,697
Forecast Cost		$101,090.88

Administration Charge Under Energy Balancing Service

Customer Charge Under BackUp Rate

Annual Cost (50% of total)	$50,545
Number of LRS	4
Monthly Administration Charge	**$1,053.03**

Standby Service: Customer Charge Calculations

Full Time Equivalent (FTE) Cost

Salary		58,098
Fringe Benefits	16.0%	$9,296
Salary (including fringe benefits)		$67,394
Administrative Overhead	50%	$33,697
Forecast Cost		$101,091

Administration Charge Under Standby Service

Annual Cost (50% of total)	$50,545
Number of LRS	4
Monthly Administration Charge	**$1,053.03**

Item # **Annual Avoided Fuel Cost Calculations**

Item #	Source		Annual GWh Load at Transmission Level	Cost	Avoided Unit Cost (c/kWh)	Comments/Assumptions
		Avoided Costs				
1	Plexus Simulations	Avoided Costs of departing customer Load before taking energy balancing service from NS Power.	219	$13,052,400	5.960	Going forward the Company intends to use forecast load and hourly loadshape of customers served in the RtR market. For the purposes of this simulation the Company used flat 25 MW decrement.
2	Plexus Simulations	Avoided Costs of departing customer Load after taking energy balancing service from NS Power	219	$11,541,300	5.270	Going forward the Company intends to use NS Power's system hourly loadshape which will reflect the combined effect of hourly load of departing customers to the RtR market and 3rd party renewable generation under assumption that some of it may be curtailed. For the purposes of this simulation the Company used only the effect of 3rd party renewable generation under no curtailment assumption.
3		Cost Differential between items 1 and 2 above		$1,511,100		This is an incremental fuel cost arising from provision of energy balancing service to departed customers
4		**Spill Energy Credit rate**			5.270	Set at par with unit avoided costs under item #2.
5		**Top-up Energy Rate Calculation**				
5.1		**Avoided Fuel Cost Component**				
5.1.1		Average avoided cost after energy balancing service			5.270	Set at par with unit avoided costs under item #2.
5.1.2		Incremental costs associated with energy balancing service	109.5	$1,511,100	<u>1.380</u>	Going forward the Company intends to use forecast annual top-up energy in the RtR market in calculation of this charge. For now a simplifying assumption was made that top-up energy accounts for 50% of the total energy consumed in the RtR market (219 GWh/2 = 109.5 GWh)
		Fuel Cost charge			**6.650**	
4.2		**Energy-related fixed cost Component**				
	Appendix C 2014 COS Costs - Exhibit 5; page 1 Energy - Exhibit 9A, line 11, col 3 divided by a transmission loss factor of 1.032.	Fixed Energy-related Cost in '000's of $	9,507,746	$314,631,000		Calculated as follows: total of $753,049 less fuel of $367,943, purchased power regular of $507, purchased biomass power $11595, purchased wind power of $59,982, purchased imports of $217; plus export sales of $1,826
		Charge in cents per kWh			3.309	
		Total top-up charge in cents per kWh			**9.959**	

STANDBY SERVICE TARIFF
Renewable to Retail

STANDBY SERVICE

Standby Service is a supplemental generation capacity service provided to Licenced Retail Suppliers (LRS). The service is provided in combination with Energy Balancing Service under the Energy Balancing Service Tariff. The service has two components:

> **Capacity adequacy service –** fulfillment of the LRS's obligation to provide or pay for its share of firm capacity required to meet adequacy standards of the Nova Scotia electricity system arising from forced and unforced generation outages. Energy delivered during generation outages will be billed under the Energy Balancing Service Tariff.
>
> **Top-up capacity service –** provision of capacity to support energy delivery through the Energy Balancing Service in respect of imbalance between load and generation.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Standby Service Tariff is applicable to the LRS to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Standby Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and.

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Standby Service Tariff shall also take service under Open Access Transmission Tariff (OATT), the Energy Balancing Service Tariff and the Renewable to Retail Market Transition Tariff.

(2) The service under this Standby Service Tariff is complementary to the generation ancillary services to the Renewable to Retail market under OATT.

(3) The aggregate hourly load quantities are determined at the delivery point from the transmission system, inclusive of distribution system losses, in accordance with the provisions of the LRS Terms and Conditions.

(4) This service is applicable to firm load only.

STANDBY SERVICE TARIFF
Renewable to Retail

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS's subscribed} * 12}$$

This charge will be $1,053.03 per month.

DEMAND CHARGE

$5.370 per month, per kilowatt (kW) of monthly standby contract demand.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

DETERMINATION OF MONTHLY STANDBY CONTRACT DEMAND

Monthly Standby Contract Demand (MSCD) in kW is determined using the following formula:

$$MSCD = LWPFD - \mathit{min}\left(LWPFD, \left(\sum_{i=1}^{n} CCi * GCi\right)/(1+PR)\right)$$

Where :

LWPFD is LRS Winter Peak Firm Demand in respect of each billing month calculated as follows:

$$LWPFD = \sum_{i=1}^{k} (CMPFDi * CMDAFi)$$

“k”   is the number of otherwise applicable bundled service rate classes to RtR customers of LRS.

“CMPFDi” is hourly kW Class Monthly Peak Firm Demand of the LRS firm load in each tariff class at the time of system coincident firm load peak in each month at transmission delivery points (i.e. inclusive of distribution system losses). The CMPFD for the unmetered customer class shall be determined by use of research based class load profile data.

STANDBY SERVICE TARIFF
Renewable to Retail

"CMDAFi" is the Class Monthly Demand Adjustment Factor applicable to each class as set out below:

Classes	Jan, Feb, Dec	Mar, Apr	May, June	Jul, Aug, Sep	Oct, Nov
Domestic	1.00	1.27	1.67	2.17	1.47
Small General	1.00	1.21	1.32	1.09	1.28
General	1.00	1.12	1.32	1.05	1.19
Large General	1.00	1.05	1.04	0.78	0.99
Small Industrial	1.00	1.06	1.01	0.94	1.00
Medium Industrial	1.00	1.14	1.08	1.01	1.02
Large Industrial Firm	1.00	1.10	1.03	0.89	1.09
Unmetered	1.00	8.24	7.90	7.68	2.28

"PR" is Planning Reserve (%) (based on Northeast Power Coordinating Council planning criteria, i.e., 20% or as updated)

"CCi" is a capacity contribution factor of LRS' generator to NS Power's system peak as determined by NS Power. The capacity contribution factor may be the subject of periodic adjustment if operating conditions of the generator, such as a prolonged deration, depart from those assumed by NS Power.

"GCi" is the generator capacity dedicated to serving LRS load.

"n" is the total number of LRS' generators including those under contract.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS's RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

STANDBY SERVICE TARIFF
Renewable to Retail

(4) Nothing contained in this Standby Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Utility and Review Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Standby Service Tariff, the Energy Balancing Service Tariff or the Renewable to Retail Market Transition Tariff.

Nova Scotia Power Incorporated
Open Access Transmission Tariff – 2014 Schedule

SCHEDULE 4: ENERGY IMBALANCE SERVICE

This Schedule 4 is not applicable to Licenced Retail Suppliers.

The Generation Forecasting Service set out in Schedule 4A of the OATT will apply to Licenced Retail Suppliers only and is not applicable to any other Eligible Customer.

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within an Operating Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

For a bilateral schedule of a single load and its single generator, this ancillary service will be applied to the net of the generation and load imbalance. Otherwise, this Ancillary Service will be applied separately to deviations from load schedules and deviations from generation schedules. This ancillary service does not apply to power exported from the Operating Area, which is covered by the Generation Balancing Service of the Standard Generator Interconnection and Operation Agreement.

Energy Imbalance Service does not apply to inadvertent energy imbalances that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;

- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Energy Imbalance Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Load Energy Imbalance Associated with Point-to-Point or Network Integration Transmission Service:

For each Transmission Customer taking service under Part II or Part III of this Tariff, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

A deviation band of +/- 1.5 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be applied hourly to any net load energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

Parties should attempt to eliminate energy imbalances within the limits of the deviation band within the billing month in accordance to the following:

- For hourly imbalances that arise during peak hours, such imbalances should be eliminated via deliveries or withdrawals during peak hours; and

- For hourly imbalances that arise during non-peak hours, such imbalances should be eliminated via deliveries or withdrawals during non-peak hours.

Net load energy imbalances within the deviation band that have not been eliminated at the end of the billing month will be subject to the charges set below:

- Energy supplied by the Transmission Provider during peak hours to compensate for a net shortfall in peak hours delivery over the billing month will be charged at the average on-peak system marginal cost for the billing month. Energy supplied by the Transmission Provider during non-peak hours to compensate for a net shortfall in non-peak hours delivery over the billing month will be charged at the average non-peak system marginal cost for the billing month.

- Energy supplied to the Transmission Provider during peak hours as a net excess of the peak hours delivery over the billing month will be purchased by the Transmission Provider at the average on-peak system marginal cost for the billing month. Energy supplied to the Transmission Provider during non-peak hours as a net excess of the non-peak hours delivery over the billing month will be purchased by the Transmission Provider at the average non-peak system marginal cost for the billing month.

Energy imbalances outside of the deviation band are not eligible for elimination and are subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net hourly shortfall in delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Dispatchable Generators:

For Dispatchable Generators in the Transmission Provider’s Operating Area supplying load in the Transmission Provider’s Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

<u>Generation Energy Imbalance - Non-Dispatchable Generators</u>

For Non-dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

Energy Imbalances inside a deviation band of +/- 10 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at the hourly system marginal cost in the hour of the deviation.

All deviations from schedule outside of the +/- 10 percent deviation band will be subject to charges as set forth below:

Nova Scotia Power Incorporated
Open Access Transmission Tariff – 2014 Schedule

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

SCHEDULE 4A: GENERATION FORECASTING SERVICE

This Generation Forecasting Service set out in Schedule 4A of the OATT applies to Licenced Retail Suppliers only and is not applicable to any other Eligible Customer. Generation Forecasting Service addresses the accuracy of generation scheduling by Licenced Retail Suppliers.

This Schedule does not apply to forecasting discrepancies that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Forecast Deviation Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Each Licenced Retail Supplier shall use commercially reasonable efforts to provide accurate schedules and forecasts of production from renewable low-impact generators that are not dispatchable.

To the extent that such schedules or forecasts of hourly production of the aggregate of a Licenced Retail Supplier's RtR generation resources deviate from the actual production for reasons other than those that occur as a result of actions directed by the Operating Area operator the following charges shall apply:

An hourly deviation band of +/- 10 percent of the aggregate hourly scheduled or forecast quantity (with a minimum deviation band of +/- 2 MW) will be applied hourly to any forecast discrepancy that occurs as a result of the Transmission Customer's scheduled transaction(s).

- Hourly forecast discrepancies falling outside the hourly deviation band during peak hours will be charged at 10% of the average on-peak system marginal cost for the billing month.
- Hourly forecast discrepancies falling outside the hourly deviation band during non-peak hours will be charged at 10% of the average non-peak system marginal cost for the billing month.

Amendments to the

Open Access Transmission Tariff

for the Renewable to Retail Application are in these sections:

Table of Contents

Part I - Common Provisions:
Section 1.0 (Definitions)
Section 3.0 (Ancillary Services)

Part III – Network Integration:
Preamble
Section 30.4 (Operation of Network Resources)

Attachment E – Standards of Conduct – Revision to title on p.1

Attachment G – Network Operating Agreement - Correction to Section reference on first page.

NOVA SCOTIA POWER INC.

OPEN ACCESS TRANSMISSION TARIFF

As approved by the UARB May 31, 2005

As Amended •

NSPI **Open Access Transmission Tariff**

TABLE OF CONTENTS

NSPI

Open Access Transmission Tariff

NSPI **Open Access Transmission Tariff**

NSPI **Open Access Transmission Tariff**

NSPI

Open Access Transmission Tariff

NSPI **Open Access Transmission Tariff**

NSPI **Open Access Transmission Tariff**

NSPI **Open Access Transmission Tariff**

NSPI **Open Access Transmission Tariff**

I COMMON SERVICE PROVISIONS

1.0 Definitions

1.0 Act: The *Electricity Act*, S.N.S. 2004, c. 25, as amended from time to time**.**

1.1 Ancillary Services: Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.2 Application: A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.3 Board: The Nova Scotia Utility and Review Board.

1.4 Bundled Service: Electrical service taken from NSPI under Rates and Regulations approved by the Board. This takes the form of having generation, transmission, distribution, ancillary services and all other items associated with the provision of such service blended or bundled within the rate. For certainty, Bundled Service does not include services taken from NSPI under the Distribution Tariff, the Energy Balancing Service Tariff, the Standby Service Tariff or the Renewable to Retail Market Transition Tariff.

1.5 Business Day: A Business Day is Monday to Friday, inclusive, excluding holidays. The regular business hours on a Business Day are from 08:30 to 16:30 Atlantic Time.

1.6 Calendar Day: Any day including Saturday, Sunday or a holiday.

1.7 Completed Application: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.8 Control Area: An electric system or group of systems that meet(s) the requirements of the NPCC Control Area Certification Process.

1.9 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.10 Delivering Party: The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.11 Designated Agent: Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.12 Direct Assignment Facilities: Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Board approval.

1.13 Dispatchable Generation: Any generation that does not meet the definition of Non-dispatchable Generation.

1.14 Eligible Customer:

(i) Any electric utility (including the Transmission Provider and any power marketer), power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico; and

(ii) Any retail customer taking unbundled transmission service pursuant to a provincial or regulatory requirement that the Transmission Provider offer the transmission service is an Eligible Customer of the Tariff.

(iii) Any Licenced Retail Supplier taking unbundled transmission service pursuant to the Act for the purpose of selling renewable low-impact electricity to RtR Customers is an Eligible Customer of the Tariff.

1.15 Facilities Study: An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.16 FERC: The U.S. Federal Energy Regulatory Commission.

1.17 Firm Point-To-Point Transmission Service: Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.18 Good Utility Practice: Those practices, methods or acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America) that at a particular time, in the exercise of reasonable judgment, would have been expected to accomplish the desired result in a manner consistent with regulations, reliability, safety, environmental protection, economy and expedition as applied and practiced in the utility industry with respect to power generation, delivery, purchase and sale.

1.19 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.19.1 Licenced Retail Supplier (LRS) : A Retail Supplier who:

(a) holds a valid Retail Supplier Licence; and

(b) has a valid LRS Participation Agreement executed with NSPI.

For certainty, a Wholesale Customer is not a Licenced Retail Supplier.

1.20 Load Shedding: The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.21 Long-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.21.1 LRS Participation Agreement: The agreement (and any amendments or supplements thereto) between a Licenced Retail Supplier and NSPI with respect to the sale of renewable low-impact electricity by the LRS in the form approved by the Board.

1.22 Native Load Customers: The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.23 NERC: North American Electric Reliability Council.

1.24 Network Customer: An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part

III of the Tariff. For clarity, the LRS is the Network Customer for the receipt of Network Integration Transmission Service in respect of the LRS's aggregate Renewable to Retail customer load.

1.25 **Network Integration Transmission Service (Network Transmission Service, Network Service):** The transmission service provided under Part III of the Tariff. Network Integration Transmission Service is applicable to the LRS's Renewable to Retail transactions on the Transmission System.

1.26 **Network Load:** The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer, who is also a Wholesale Customer as defined herein, may elect to designate less than its total load as Network Load, with the remaining load at the discrete Point of Delivery treated as bundled service under the appropriate Rate Class. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.27 **Network Operating Agreement:** An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.28 **Network Operating Committee:** A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.29 Network Resource: Any designated generating resource or dedicated transmission equipment owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.30 Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network upgrades shall be subject to Board approval.

1.31 Non-dispatchable Generation: Generators delivering energy from sources which, by their nature, cannot be controlled on demand by the operator. These generators deliver energy directly to the grid as produced, without the use of energy storage technology. Examples include wind energy conversion systems, photovoltaic systems, tidal or wave power, and run-of-river hydro systems. The Transmission Provider will determine if the generation meets this designation, and evidence of market manipulation will result in disqualification.

1.32 Non-Firm Point-To-Point Transmission Service: Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.33 NPCC: The Northeast Power Coordinating Council.

1.33.1 NSPI: Nova Scotia Power Inc.

1.34 **Open Access Same-Time Information System (OASIS):** An electronic medium information system, which provides Open Access Transmission Customers with relevant information regarding available transmission capacity, prices, and other matters to enable them to obtain open access non-discriminatory transmission services from the Transmission Provider.

1.35 **Operating Area:** An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Operating Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.36 **Part I:** Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.37 **Part II:** Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.38 Part III: Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.39 Parties: The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.40 Peak Load/Peak Demand: The electric load that corresponds to a maximum level of electricity demand in a specified time period.

1.41 Point(s) of Delivery: Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.42 Point(s) of Receipt: Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.43 Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.44 Power Pool: Two or more interconnected electric systems planned and operated to supply power for their combined demand requirements.

1.45 **Power Purchaser:** The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.46 **Receiving Party:** The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.47 **Regional Transmission Group (RTG):** A voluntary organization of transmission owners, transmission users and other entities formed to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.47.1 Renewable low-impact electricity: This term has the same meaning as in the Renewable Electricity Regulations (Nova Scotia).

1.47.2 Renewable to Retail: Describes the market in which renewable low-impact electricity generated in Nova Scotia may be sold by Licenced Retail Suppliers to Retail Customers in Nova Scotia in accordance with the Act.

1.47.3 RtR Customer: A Retail Customer who is acquiring renewable low-impact electricity from an LRS and is not receiving Bundled Service from NSPI.

1.47.4 Retail Customer: This term has the same meaning as under the Act. For certainty, a customer of a municipal utility (as defined under the Act) is not a Retail Customer.

1.47.5 Retail Supplier: This term has the same meaning as under the Act.

1.48 **Reserved Capacity:** The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a 60 minute interval (commencing on the clock hour) basis.

1.49 Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.50 Service Commencement Date: The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.51 Short-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.52 System Impact Study: An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.53 Third-Party Sale: Any sale for resale of generation capacity or energy to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.54 Transmission Customer: Any Eligible Customer (or its Designated Agent) that executes a Service Agreement, or requests in writing that the Transmission Provider file with the Board, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I

Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.55 Transmission Provider: Nova Scotia Power Inc.

1.56 Transmission Service: Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.57 Transmission System: The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

1.58 Wholesale Customer: This term has the same meaning as under the Act.

2.0 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transmission Capability: For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial 60 day period commencing with the effective date of the Tariff will be deemed to have been received simultaneously. Such Transmission Service requests will be evaluated and ranked in a decreasing order according to the net present value of their stream of revenues. Reservation priorities shall be assigned to such Transmission Service requests in accordance with the ranking order so established, beginning with the Transmission Service request(s) with the highest net present value. If there is not enough remaining transmission capability to accommodate all of the requests equally ranked, a lottery system conducted by an independent party shall be used to assign priorities for such requests. Subsequent to this initial 60 day period, when new total transfer capability is identified the above noted process will be repeated. Otherwise, all completed Applications for firm transmission service received after the initial 60 day period shall be assigned a priority pursuant to Section 13.2. Extensions for commencement of service shall be in accordance with Section 17.7.

2.2 Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service, the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible

Customer and to pay the current Tariff for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one year or longer.

2.3 Reliability Compliance: All rights and obligations of the Transmission Provider and Transmission Customers receiving Transmission Service under the Tariff shall be subject to the reliability guidelines of NPCC, or its successors, and any amendments thereto.

3.0 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Operating Areas affected by the transmission service. The Transmission Provider is required to provide and the Transmission Customer is required to purchase, the following Ancillary Services:

(i) Scheduling, System Control and Dispatch, and

(ii) Reactive Supply and Voltage Control from Generation Sources.

(iii) Generation Forecasting Service.

Provided, however, Generation Forecasting Service is only applicable to Eligible Customers who are Licenced Retail Suppliers. The Transmission Provider is only required to provide to Licenced Retail Suppliers, and only Licenced Retail Suppliers are required to purchase from the Transmission Provider, Generation Forecasting Service.

The Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Operating Area, with the exception that the Transmission Provider is not required to offer to provide Energy Imbalance Service to Licenced Retail Suppliers and Licenced Retail Suppliers are not required to purchase Energy Imbalance Service from the Transmission

Provider as Energy Imbalance Service is not applicable to Eligible Customers who are Licenced Retail Suppliers:

(i) Regulation and Frequency Response,
(ii) Energy Imbalance,
(iii) Operating Reserve - Spinning, and
(iv) Operating Reserve - Supplemental.

The Transmission Customer serving load within the Transmission Provider's Operating Area is required to acquire these Ancillary Services whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services, unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.6 below list the seven Ancillary Services.

Deleted: six

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation Sources Service: The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4 (Not applicable to Licenced Retail Suppliers).

3.4.1 Generation Forecasting Service: Where applicable the rates and/or methodology are described in Schedule 4A (Applicable to Licenced Retail Suppliers only).

3.5 Operating Reserve - Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve - Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6.

4.0 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are based on 18 CFR § 37 of the FERC regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities). The Transmission Provider's Standards of Conduct are attached to this Tariff as Attachment E. In the event available transmission capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

5.0 [Section not used at this time]

6.0 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates. A Transmission Customer that is a member of a power pool or Regional Transmission Group also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, power buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7.0 Billing and Payment

7.1 Billing Procedure: Within a reasonable time after the first day of each month, the Transmission Provider or its Designated Agent shall submit an invoice to the

Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within 20 Calendar Days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider.

7.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified in Regulation 5.4 of NSPI's Rates, Regulations and Procedures as issued by the Board. When payments are made by mail, bills shall be considered as paid on time if the envelope is post marked on or before the last date for net payment.

7.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within 30 Calendar Days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may terminate service. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in 60 days.

8.0 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues: Include in a separate operating revenue account the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues: Include in a separate transmission operating expense account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9.0 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Board for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights.

10.0 Force Majeure and Indemnification

10.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing by any party. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

10.3 Limitation of Liability: The Transmission Provider shall not be responsible for any claim, action, loss, injury, damage or proceeding whatsoever as a result of any interruptions, diversions, curtailments, or other procedures necessary to maintain the efficient and effective operation of the Transmission System. This would include all Transmission Service as permitted by this Tariff, except if such claim, action, proceeding or loss is due to the Transmission Provider's negligence, undue discrimination or willful misconduct.

11.0 Creditworthiness

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established under the law of the Province of Nova Scotia that protects the Transmission Provider against the risk of non-payment.

12.0 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer or Eligible Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Board for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer or Eligible Customer, as the case may be, for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within 30 days by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures: Any arbitration initiated under the Tariff shall be conducted before a single arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within 20 days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall conduct the arbitration in Halifax, N.S. and shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the *Commercial Arbitration Act* S.N.S 1999, c.5.

12.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within 90 days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the *Commercial Arbitration Act* S.N.S 1999*, c.5*. The final decision of the arbitrator must also be filed with the Board if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(a) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(b) one half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under the Public Utilities Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Board.

II. POINT-TO-POINT TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

13.0 Nature of Firm Point-To-Point Transmission Service

13.1 Term: The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority: Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis i.e., in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transmission capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service has the right of first refusal to match any longer term reservation before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff. Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales.

The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements: The Transmission Provider shall offer a standard form for Long-Term Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form for Short-Term Firm and Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm (or Non-Firm) Point-To-Point Transmission Service pursuant to the Tariff.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs: In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (i) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point

Transmission Service, or (ii) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, or the systems directly or indirectly interconnected with the Transmission Provider’s Transmission, curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service:

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may

(1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or

(2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the

Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The Transmission Customer's Reserved Capacity shall be greater of either**:**

(1) the sum of the capacity reservations at the Point(s) of Receipt, or

(2) the sum of the capacity reservations at the Point(s) of Delivery.

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. A Transmission Customer may not exceed its Firm capacity reservation at the Point of Receipt or the Point of Delivery. In the event that the reserved capacity at the Point of Receipt or the Point of Delivery is exceeded, the Transmission Customer shall pay 150% of the charge for the service under contract, regardless of whether the service was offered at a discount at the time of such violation, which is otherwise applicable to each MW of the excess.

13.8 Scheduling of Firm Point-To-Point Transmission Service: Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 11.00 a.m. Atlantic Time (or a revised time as posted on the OASIS) of the day prior to commencement of such service. Schedules submitted after 11:00 a.m. Atlantic Time (or a revised time as posted on the OASIS) will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to 30 minutes (or a revised time as posted on the OASIS) before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.0 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term: Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one hour to one month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority: Non-Firm Point-To-Point Transmission Service shall be available from transmission capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned to reservations with a longer duration of service. In the event the Transmission System is constrained, competing requests of equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales.

14.4 Service Agreements: The Transmission Provider shall offer a standard form for Short-Term Firm and Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm (or Short-Term Firm) Point-To-Point Transmission Service pursuant to the Tariff.

14.5 Classification of Non-Firm Point-To-Point Transmission Service: Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff.

A Transmission Customer may not exceed its Non-Firm capacity reservation at the Point of Receipt and the Point of Delivery. In the event that the reserved capacity at the Point of Receipt or the Point of Delivery is exceeded, the Transmission Customer shall pay 150% of the charge for the service under contract, regardless of whether the service was offered at a discount at the time of such violation, which is otherwise applicable to each MW of the excess.

Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Schedules for Non-Firm Point-To-Point Transmission Service, other than hourly Non-Firm Point-to-Point Transmission Service, must be submitted to the Transmission Provider no later than 11:00 a.m. Atlantic Time (or a revised time as posted on the OASIS) of the day prior to commencement of such service. Schedules submitted after 11:00 a.m. Atlantic Time (or a revised time as posted on the OASIS) will be accommodated, if practicable. Schedules of energy that are to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to 30 minutes (or a revised time as posted on the OASIS) before the start of the next clock hour provided that the Delivering Party and Receiving

Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service: The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly or indirectly interconnected with the Transmission Provider's Transmission System. The Transmission Provider reserves the right to interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate:

(1) a request for Firm Transmission Service,

(2) a request for Non-Firm Point-To-Point Transmission Service of greater duration,

(3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, or

(4) transmission service for Network Customers from non-designated resources.

The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (by way of example, hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment.

15.0 Service Availability

15.1 General Conditions: The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transmission Capability: A description of the Transmission Provider's specific methodology for assessing available transmission capability posted on the OASIS used by Transmission Provider (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transmission capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study subject to the provisions of Section 19.

15.3 Initiating Service in the Absence of an Executed Service Agreement: If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Board, within 30 days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to:

(i) compensate the Transmission Provider at the rate that the Board ultimately determines to be just and reasonable, and

(ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System: If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, and subject to receiving all necessary approvals from the Board, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

15.5 Deferral of Service: The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 [Section not used at this time]

15.7 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are set forth in Schedule 9 of this Tariff.

16.0 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers: Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

a) The Transmission Customer has pending a Completed Application for service;

b) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

c) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation; and

e) The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17.0 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application: A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written application (Attachment A: Form for Long-Term Firm Point-To-Point Transmission Service Agreement) to the address posted on the OASIS used by the Transmission Provider.

Applications must be postmarked at least 60 days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. Submission of an enabling agreement (Attachment B: Form for Short-Term Firm and Non-Firm Point-To-Point Transmission Service Agreement) must precede or accompany a Transmission Customer's first request for Short-Term Firm (or Non-Firm) Transmission Service. All Firm Point-To-Point Transmission Service requests for periods of less than one year shall be submitted by entering the information listed in Section 17.2 on the OASIS used by the Transmission Provider. Prior to implementation of the OASIS, or if the OASIS used by the Transmission Provider is not functioning, a Completed Application may be submitted by transmitting the required information to the Transmission Provider by fax. This will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application: A Completed Application shall provide all of the information including but not limited to the following:

(i) The identity, address, e-mail address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, or by law for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements.

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service; and

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement.

The Transmission Provider shall treat this information consistent with its Standards of Conduct.

17.3 **Deposit:** A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission

Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be calculated in accordance with Regulation 7.1(i) in NSPI’s Rates, Regulations & Procedures as issued by the Board.

17.4 Notice of Deficient Application: If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within 15 days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application: Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission

Provider shall make a determination of available transmission capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than 30 days after the date of receipt of a Completed Application either

(i) if it will be able to provide service without performing a System Impact Study or

(ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution of Service Agreement: Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than 30 days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within 15 days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to submit another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service: The Transmission Customer can obtain up to 5 one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within 30 days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18.0 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application: Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application (Attachment B: Form For Short-Term Firm and Non-Firm Point-To-Point Transmission Service Agreement) to the Transmission Provider prior to or accompanying the first request for Non-Firm (or Short-Term Firm) Transmission Service. Specific requests for Non-Firm Transmission Service should be submitted by entering the information listed in Section 18.2 on the OASIS used by the Transmission Provider. Prior to implementation of the OASIS, or if the OASIS used by the Transmission Provider is not functioning, a Completed Application may be submitted by transmitting the required information to the Transmission Provider by fax. This will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application: A Completed Application shall provide all of the information including but not limited to the following:

(i) The identity, address, e-mail address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order or by law, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with its Standards of Conduct.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service: Requests for monthly service shall be submitted no earlier than 60 days before service is to commence; requests for weekly service shall be submitted no earlier than 14 days before service is to commence, requests for daily service shall be submitted no earlier than two Business Days before service is to commence, and requests for hourly service shall be submitted no earlier than 12:00 (noon) Atlantic Time of the Business Day before service is to commence. Requests for service received later than 12:00 p.m. (noon) Atlantic Time of the Business Day prior to the day service is scheduled to commence will be accommodated if practicable.

18.4 Determination of Available Transmission Capability: Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transmission capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service:

(i) thirty minutes for hourly service,
(ii) one hour for daily service,
(iii) four hours for weekly service, and
(iv) two days for monthly service.

19.0 Additional Study Procedures For Firm Point-To-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within 30 days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within 15 days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

19.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a 60 day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within 15 days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 **Facilities Study Procedures:** If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within 30 days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within 15 days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a 60 day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of:

(i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer,

(ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and

(iii) the time required to complete such construction and initiate the requested service.

The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the Transmission Customer’s share of the costs of new facilities or upgrades. The Transmission Customer shall have 30 days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications: Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities: Subject to receiving all necessary approvals from the Board, the Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service: If the Transmission Provider determines that it will not have adequate transmission capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within 30 days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within 15 days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

20.0 Procedures if The Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within 30 days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions: When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the

Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Long-Term Firm Point-To-Point Transmission Service. If the alternative approach solely involves Short-Term Firm or Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Short-Term Firm or Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12.

20.3 Refund Obligation for Unfinished Facility Additions: If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest. However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21.0 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions: The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good

Utility Practice. The Transmission Customer shall reimburse the Transmission Provider for all reasonably incurred costs arising from the Transmission Provider's obligation to undertake such efforts.

21.2 Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within 60 days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12.

22.0 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the submission of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification On a Firm Basis: Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23.0 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service: A Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. A Reseller should notify the Transmission Provider as soon as possible after any assignment or transfer of service occurs but in any event, notification must be provided prior to any provision of service to the Assignee. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Parties through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service: In accordance with Section 4, Resellers may use the OASIS used by the Transmission Provider to post transmission capacity available for resale.

24.0 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Provider shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information as required. Such equipment shall remain the property of the Transmission Provider. At the Point of Receipt, the Transmission Customer will pay the associated costs. At the Point of Delivery, the Transmission Provider will pay the metering costs in accordance with NSPI's Rates, Regulations and Procedures, Section 4.

24.2 Transmission Provider Access to Metering Data: The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable. In lieu of any specific power factor requirements in the relevant Service Agreement, the penalty for a power factor less than 90% shall be based on Excess kVA.

Excess kVA is defined as:

Excess kVA = Max. kVA – Max. kW / 0.9

Where

Max. kVA = Maximum hourly kVA consumed during the month

Max. kW = Maximum hourly kW consumed during the month

The charge per Excess kVA will be the demand charge of the NSPI Large Industrial Rate as set by the Board from time to time.

25.0 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Long-Term Firm and Short Term Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26.0 Stranded Cost Recovery

The Transmission Provider reserves the right to seek recovery of stranded costs from the Transmission Customer pursuant to this Tariff. However, the Transmission Provider must separately file any proposal to recover stranded costs with the Board.

27.0 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs as determined by the Transmission Provider. Whenever a System Impact Study performed by the Transmission

Provider identifies capacity constraints that may be relieved more economically by redispatching the Transmission Provider's resources than by building new facilities or upgrading existing facilities to eliminate such constraints, the Transmission Customer shall be responsible for such redispatch costs.

NSPI Open Access Transmission Tariff

III. NETWORK INTEGRATION TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

Network Integration Transmission Service is applicable to the LRS's Renewable to Retail transactions on the Transmission System.

28.0 Nature of Network Integration Transmission Service

28.1 Scope of Service: Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Operating Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities: The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration

Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transmission capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service: The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service: The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to replace Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are set forth in Schedule 9 of this Tariff.

28.6 Restrictions on Use of Service: The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System.

29.0 Initiating Service

29.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that:

(i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff,

(ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4,

(iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Board, and

(iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G.

29.2 Application Procedures: An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications shall be submitted by entering the information listed below on the OASIS used by the Transmission Provider. Prior to implementation of the OASIS, or if the OASIS used by the Transmission Provider is not functioning, a Completed Application may be submitted by transmitting the required information to the Transmission Provider by fax. This will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall include, but not be limited to, all of the following information:

(i) The identity, address, e-mail address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the ten year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and ten year projections), which shall include, for each Network Resource:

1. Unit size and amount of capacity from that unit to be designated as Network Resource
2. Seasonal capacity rating as required by the NPCC
3. VAR capability (both leading and lagging) of all generators
4. Operating restrictions
    a. Any periods of restricted operations throughout the year
    b. Maintenance schedules
    c. Minimum loading level of unit
    d. Normal operating level of unit
    e. Any must-run unit designations required for system reliability or contract reasons
5. Load and frequency control capability
6. Dispatchability and maneuverability
7. Approximate variable generating cost ($/MWH) for redispatch computations
8. Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Operating Area, where only a portion of unit output is designated as a Network Resource

9. Description of purchased power designated as a Network Resource including source of supply, Operating Area location, transmission arrangements and delivery point(s) to the Transmission Provider's Transmission System;

(vi) Description of Eligible Customer's transmission system:

1. Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a format compatible with that used by the Transmission Provider
2. Operating restrictions needed for reliability
3. Operating guides employed by system operators
4. Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
5. Location of Network Resources described in subsection (v) above
6. Ten year projection of system expansions or upgrades
7. Transmission System maps that include any proposed expansions or upgrades
8. Thermal ratings of Eligible Customer's Operating Area ties with other Operating Areas; and

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within 15 days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer submitting a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with its Standards of Conduct.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service: Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities: The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

30.0 Network Resources

30.1 Designation of Network Resources: Network Resources shall include all generation and dedicated transmission equipment owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources: The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made by a request for modification of service by submitting a new Application under Section 29.

30.3 Termination of Network Resources: The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource at any time but should provide notification to the Transmission Provider as soon as reasonably practicable.

30.4 Operation of Network Resources: Unless otherwise agreed in writing, or provided under the terms and conditions of a Board approved tariff, the Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Operating Area such that the output of those facilities exceeds its designated Network Load, plus non-firm sales delivered pursuant to Part II of the Tariff, plus losses. This limitation shall not apply to

Deleted: T

changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

30.5 Network Customer Redispatch Obligation: As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider: The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources: The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network

Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities: The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under Part III of the Tariff, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with the Transmission Provider. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31.0 Designation of Network Load

31.1 Network Load: The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider: The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer.

31.3 Network Load Not Physically Interconnected with the Transmission Provider: This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of:

(1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or

(2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates: The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32.0 Additional Study Procedures For Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within 30 days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within 15 days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a 60 day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within 15 days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within 30 days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within 15 days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a 60 day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of:

(i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer,

(ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and

(iii) the time required to complete such construction and initiate the requested service.

The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades. The Eligible Customer shall have 30 days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

33.0 Load Shedding and Curtailments

33.1 Procedures: Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System or on systems directly or indirectly interconnected with the Transmission Provider’s Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints: During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost.

33.4 Curtailments of Scheduled Deliveries: If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to curtail scheduled deliveries, the Parties shall curtail such schedules in accordance with the Network Operating Agreement.

33.5 Allocation of Curtailments: The Transmission Provider shall, on a non-discriminatory basis, curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective loads. The Transmission Provider shall not direct the Network Customer to curtail schedules to an extent greater than the Transmission Provider would curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding: To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability: Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may curtail Network Integration Transmission Service in order to:

(i) limit the extent or damage of the adverse condition(s) or disturbance(s),

(ii) prevent damage to generating or transmission facilities, or

(iii) expedite restoration of service.

The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34.0 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, along with the following:

34.1 Monthly Demand Charge: The Network Customer shall pay a Demand Charge based on the Network Customer’s net non-coincident monthly peak demand as specified in Schedule 10.

34.2 [Section not used at this time]:

34.3 [Section not used at this time]:

34.4 Redispatch Charge: The Network Customer shall pay redispatch charges pursuant to Section 33 as specified in Schedule 10. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery: The Transmission Provider reserves the right to seek recovery of stranded costs from the Network Customer pursuant to this Tariff. However, the Transmission Provider must separately file any proposal to recover stranded costs with the Board.

34.6 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable. In lieu of any specific power factor requirements in the relevant Service Agreement, the penalty for a power factor less than 90% shall be based on Excess kVA. Excess kVA is defined as:

Excess kVA = Max. kVA – Max. kW / 0.9
Where
Max. kVA = Maximum hourly kVA consumed during the month
Max. kW = Maximum hourly kW consumed during the month

The charge per Excess kVA will be the demand charge of the NSPI Large Industrial Rate as set by the Board from time to time.

35.0 Operating Arrangements

35.1 Operation under The Network Operating Agreement: The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement: The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to:

(i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment),

(ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data),

(iii) use software programs required for data links and constraint dispatching,

(iv) exchange data on forecasted loads and resources necessary for long-term planning, and

(v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols.

The Network Operating Agreement will recognize that the Network Customer shall either:

(i) operate as a Control Area under applicable guidelines of NERC and NPCC, or their successors;

(ii) satisfy its Operating Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or

(iii) satisfy its Operating Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC, or their successors;

The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee: A Network Operating Committee (Committee) may be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

NSPI

Open Access Transmission Tariff

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into an Operating Area. This service can be provided only by the operator of the Operating Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Operating Area operator. The charges, payable monthly, for Scheduling, System Control and Dispatch Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Point-to-Point Transmission Service:

Delivery Period	Charge ($)
Yearly	One twelfth of $2,794.12/MW of Reserved Capacity per year
Monthly	$232.84/MW of Reserved Capacity per month
Weekly	$53.73/MW of Reserved Capacity per week
On-Peak Daily	$10.75/MW of Reserved Capacity per day
Off-Peak Daily	$7.66/MW of Reserved Capacity per day
On-Peak Hourly	$0.67/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.32/MW of Reserved Capacity per hour

On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

Network Integration Transmission Service:

$181.18/MW of Network Integration Transmission Service per month.

NSPI

Open Access Transmission Tariff

SCHEDULE 2

Reactive Supply and Voltage Control from Generation Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities (in the Operating Area where the Transmission Provider’s transmission facilities are located) under the control of the operating area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Operating Area operator. The charges, payable monthly, for such service are based on the rates set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Operating Area operator.

Point-to-Point Transmission Service:

Delivery Period	Charge ($)
Yearly	One twelfth of $3,522.47/MW of Reserved Capacity per year
Monthly	$293.54/MW of Reserved Capacity per month
Weekly	$67.74/MW of Reserved Capacity per week
On-Peak Daily	$13.55/MW of Reserved Capacity per day
Off-Peak Daily	$9.65/MW of Reserved Capacity per day
On-Peak Hourly	$0.85/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.40/MW of Reserved Capacity per hour

(On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.)

Network Integration Transmission Service:

$227.99/MW of Network Integration Transmission Service per month.

NSPI **Open Access Transmission Tariff**

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Operating Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The charges, payable monthly, for Regulation and Frequency Response Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Regulation (Point-to-Point Transmission Service):

The minimum period for which this service is available from the Transmission Provider is one day.

Delivery Period	Charge ($)
Yearly	One twelfth of $943.21/MW of Reserved Capacity per year
Monthly	$78.60/MW of Reserved Capacity per month
Weekly	$18.14/MW of Reserved Capacity per week
Daily	$2.58/MW of Reserved Capacity per day

Regulation (Network Integration Transmission Service):

$78.60/MW of Network Integration Transmission Service per month.

Load Following (Point-to-Point Transmission Service):

The minimum period for which this service is available from the Transmission Provider is one day.

Delivery Period	Charge ($)
Yearly	One twelfth of $5,397.63/MW of Reserved Capacity per year
Monthly	$449.80/MW of Reserved Capacity per month
Weekly	$103.80/MW of Reserved Capacity per week
Daily	$14.79/MW of Reserved Capacity per day

Load Following (Network Integration Transmission Service):

$449.80/MW of Network Integration Transmission Service per month.

Customer Obligations for Self-Supply and Third-Party Supply:

The customer obligation for self-supply or third-party supply of Regulation is equal to 1.4% of Reserved Capacity for Point-to-Point Transmission Service and 1.4% of the Network Load for

Network Integration Transmission Service.

The customer obligation for self-supply or third-party supply of Load Following is equal to 8.0% of Reserved Capacity for Point-to-Point Transmission Service and 8.0% of Network Load for Network Integration Transmission Service.

SCHEDULE 4

NOTE TO READER: NSPI HAS PROPOSED AMENDING OATT 2014 SCHEDULE 4 AND THE ADDITION OF A NEW OATT SCHEDULE 4A (GENERATION FORECASTING SERVICE) WHICH HAVE BEEN PROVIDED SEPARATELY WITH THE COMPANY'S APPLICATION).

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within an Operating Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

For a bilateral schedule of a single load and its single generator, this ancillary service will be applied to the net of the generation and load imbalance. Otherwise, this Ancillary Service will be applied separately to deviations from load schedules and deviations from generation schedules. This ancillary service does not apply to power exported from the Operating Area, which is covered by the Generation Balancing Service of the Standard Generator Interconnection and Operation Agreement.

Energy Imbalance Service does not apply to inadvertent energy imbalances that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;

- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;

- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Energy Imbalance Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Load Energy Imbalance Associated with Point-to-Point or Network Integration Transmission Service:

For each Transmission Customer taking service under Part II or Part III of this Tariff, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

A deviation band of +/- 1.5 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be applied hourly to any net load energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

Parties should attempt to eliminate energy imbalances within the limits of the deviation band within the billing month in accordance to the following:

- For hourly imbalances that arise during peak hours, such imbalances should be eliminated via deliveries or withdrawals during peak hours; and

- For hourly imbalances that arise during non-peak hours, such imbalances should be eliminated via deliveries or withdrawals during non-peak hours.

Net load energy imbalances within the deviation band that have not been eliminated at the end of the billing month will be subject to the charges set below:

- Energy supplied by the Transmission Provider during peak hours to compensate for a net shortfall in peak hours delivery over the billing month will be charged at the average on-peak system marginal cost for the billing month. Energy supplied by the Transmission Provider during non-peak hours to compensate for a net shortfall in non-peak hours delivery over the billing month will be charged at the average non-peak system marginal cost for the billing month.

- Energy supplied to the Transmission Provider during peak hours as a net excess of the peak hours delivery over the billing month will be purchased by the Transmission Provider at the average on-peak system marginal cost for the billing month. Energy supplied to the Transmission Provider during non-peak hours as a net excess of the non-peak hours delivery over the billing month will be purchased by the Transmission Provider at the average non-peak system marginal cost for the billing month.

Energy imbalances outside of the deviation band are not eligible for elimination and are subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net hourly shortfall in delivery will be charged at 110% of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90% of the hourly system marginal cost in the hour of the deviation.

<u>Generation Energy Imbalance - Dispatchable Generators:</u>

For Dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110% of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90% of the hourly system marginal cost in the hour of the deviation.

<u>Generation Energy Imbalance - Non-Dispatchable Generators:</u>

For Non-dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

Energy Imbalances inside a deviation band of +/- 10% of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at the hourly system marginal cost in the hour of the deviation.

All deviations from schedule outside of the +/- 10% deviation band will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110% of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90% of the hourly system marginal cost in the hour of the deviation.

NSPI **Open Access Transmission Tariff**

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The charges, payable monthly, for Spinning Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

<u>Point-to-Point Transmission Service:</u>

The minimum period for which this service is available from the Transmission Provider is one day.

Delivery Period	Charge ($)
Yearly	One twelfth of $1,102.97/MW of Reserved Capacity per year
Monthly	$91.91/MW of Reserved Capacity per month
Weekly	$21.21/MW of Reserved Capacity per week
Daily	$3.02/MW of Reserved Capacity per day

Network Integration Transmission Service:

$91.91/MW of the Network Integration Transmission Service per month.

Customer Obligations for Self-supply and Third-party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve – Spinning Reserve is equal to 1.40% of the Transmission Customer's reserved capacity for Point-to-Point Transmission Service and 1.40% of the Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110% of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers. This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Operating Reserve service will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

NSPI

Open Access Transmission Tariff

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service (also referred to as Contingency Reserve – Supplemental) is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The charges, payable monthly, for Supplemental Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Operating Reserve – Supplemental (10 minute):

Point-to-Point Transmission Service:

The minimum period for which this service is available from the Transmission Provider is one day.

Delivery Period	**Charge ($)**
Yearly	One twelfth of $2,447.29/MW of Reserved Capacity per year
Monthly	$203.94/MW of Reserved Capacity per month
Weekly	$47.06/MW of Reserved Capacity per week
Daily	$6.70/MW of Reserved Capacity per day

<u>Network Integration Transmission Service:</u>

$203.94/MW of the Network Integration Transmission Service per month.

Customer Obligations for Self-supply and Third-Party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve – Supplemental Reserve will be equal to 5.6% of Reserved Capacity for Point-to-Point Transmission Service and 5.6% of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110% of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

Operating Reserve – Supplemental (30 minute):

Point-to-Point Transmission Service:

The minimum period for which this service is available from the Transmission Provider is one day.

Delivery Period	Charge ($)
Yearly	One twelfth of $2,346.46/MW of Reserved Capacity per year
Monthly	$195.54/MW of Reserved Capacity per month
Weekly	$45.12/MW of Reserved Capacity per week
Daily	$6.43/MW of Reserved Capacity per day

Network Integration Transmission Service:

$195.54/MW of the Network Integration Transmission Service per month.

Customer Obligations

The customer obligation for reserves is equal to 2.8% of Reserved Capacity for Point-to-Point Transmission Service and 2.8% of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110% of the stated MW amount within 30 minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for at least 60 minutes from the time of activation.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

NSPI

Open Access Transmission Tariff

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery**: one-twelfth of the demand charge of $42,970.59/MW of Reserved Capacity per year.

2) **Monthly delivery**: $3,580.88/MW of Reserved Capacity per month.

3) **Weekly delivery**: $826.36/MW of Reserved Capacity per week.

4) **On-Peak Daily delivery**: $165.27/MW of Reserved Capacity per day.

5) **Off-Peak Daily Delivery:** $117.73/MW of Reserved Capacity per day

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section (3) above times the highest amount in megawatts of Reserved Capacity in any day during such week.

6) **Discounts**: Three principal requirements apply to discounts for transmission service as follows:

(i) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

(ii) any customer-initiated requests for discounts (including requests for use by one's Wholesale Merchant or an affiliate's use) must occur solely by posting on the OASIS, and

(iii) once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

7) On-Peak days for this service are defined as Monday to Friday.

NSPI **Open Access Transmission Tariff**

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery**: $3,580.88/MW of Reserved Capacity per month.

2) **Weekly delivery**: $826.36/MW of Reserved Capacity per week.

3) **On-Peak Daily delivery**: $165.27/MW of Reserved Capacity per day.

4) **Off-Peak Daily Delivery:** $117.73/MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section (2) above times the highest amount in megawatts of Reserved Capacity in any day during such week.

5) **On-Peak Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $10.33/MWh.

6) **Off-Peak Hourly delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $4.91/MWh.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in Section (3) above times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in Section (2) above times the highest amount in megawatts of Reserved Capacity in any hour during such week.

7) **Discounts**: Three principal requirements apply to discounts for transmission service as follows:

(i) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

(ii) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and

(iii) once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

8) On-Peak days for this service are defined as Monday to Friday.

9) On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

NSPI

Open Access Transmission Tariff

SCHEDULE 9

Real Power Loss Factors

For Point-to-Point service, the Transmission Provider will seasonally calculate loss factors to be used on a path-by-path basis. For each season, winter and summer, the power flow models used to calculate the losses will include peak and off-peak hours to derive an average loss factor for each path. For long-term Point-to-Point service, the annual loss factor to be used for a particular path is the average of the seasonal values. The loss factors will be posted on the Transmission Provider's OASIS site.

For Network Service, the Transmission Provider will apply the system average loss factor of 3.15%. This factor will be reviewed annually and is subject to change annually. It will be posted on the OASIS.

Transmission Customers are required to provide the losses associated with their service. All Transmission Customers are required to include an amount of additional capacity in their service requests sufficient to carry the losses associated with their service.

Locational Loss Factors for new generation will be determined during the System Impact Study and be applied to generation dispatch merit order if such generation is to be economically dispatched by the Transmission Provider. If the generator is self-dispatched, loss factors will be applied to determine the unit net output.

Locational Loss Factors for each generator will be determined on an annual basis and will be posted on the OASIS.

NSPI **Open Access Transmission Tariff**

SCHEDULE 10

Network Integration Transmission Service Rate

Energy Imbalance Service does not apply to deviations in scheduled delivery of energy from Non-dispatchable Generation sources to Network Load inside the Transmission Provider's Operating Area.

1. The rate charged for Network Integration Transmission Service is $2,782.20/MW-m, based on the Transmission Customer's Net Non-coincident Monthly Peak Demand.

2. Net Non-coincident Monthly Peak Demand is the maximum hourly demand at each Point of Delivery designated as Network Load (including its designated Network Load not physically interconnected to the Transmission Provider's Transmission System).

3. Transmission congestion charges will be applied as follows:

$$A = B \times (C/D)$$

Where

A = the Network Customer's congestion charge for all hours of the month that congestion redispatch costs occurred.

B = Total redispatch costs during the month.

C = The Network Customer's load during the hours for which redispatch costs were incurred.

D = The sum of all Network Integration Transmission Service load (including load served by the Transmission Provider) and Point-to-Point Transmission Service scheduled serving load in the Operating area during the hours of the month for which redispatch costs were incurred.

Open Access Transmission Tariff

ATTACHMENT A

Form For
Long-Term Firm Point-To-Point Transmission Service Agreement

1.0 This Service Agreement, dated as of _______________, is entered into, by and between Nova Scotia Power Incorporated (the Transmission Provider), and ____________ (the "Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Long-Term Firm Point-To-Point Transmission Service under Section 17.2 of the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed. Service under this agreement shall terminate on such date as set forth in the attached specifications for Long-Term Firm Point-to-Point Transmission Service incorporated herein.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Long-Term Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

NSPI **Open Access Transmission Tariff**

Transmission Provider:

Mailing Address as posted on OASIS

Transmission Customer:

Company Name: ____________________
Billing Contact: ____________________
Address: ____________________
____
Telephone: ____________________
Fax: ____________________
E-mail ____________________
TSIN Code ____________________
TSIN DUNS ____________________
Administrative Contact: ____________________
Address: ____________________
____
Telephone: ____________________
Fax: ____________________
E-mail ____________________

7.0 No failure by the Transmission Provider or the Transmission Customer at any time or from time to time to enforce or require a strict observance of any of the provisions of this Service Agreement shall constitute a waiver of the provision or affect or impair such provisions or the right of the Transmission Provider or the Transmission Customer at any time to enforce such provisions or to avail itself of any remedy it may have.

8.0 This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and any Assignees of the Transmission Customer authorized pursuant to Section 23.1 of the Tariff.

9.0 The Tariff and the attached Specifications for Long-Term Firm Point-to-Point Transmission Service are incorporated herein and made a part hereof.

10.0 Applicable taxes shall be added to all charges set forth in the Tariff.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ____________________________ ______________________ ______________________

Name Title Date

Transmission Customer:

By: ____________________________ ______________________ ______________________

Name Title Date

NSPI **Open Access Transmission Tariff**

Specifications For Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ____________________

Start Date: ____________________

Termination Date: ____________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Operating area in which the transaction originates.

____

3.0 Point(s) of Receipt: ____________________

Delivering Party: ____________________

4.0 Point(s) of Delivery: ____________________

Receiving Party: ____________________

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

____

6.0 Designation of party(ies) subject to reciprocal service obligation:

____

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service:

____

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:____

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:________________________________

____

8.4 Ancillary Services Charges: _______________________________________

____

____

____

____

____

8.5 Redispatch Charge:

____

____

8.6 Network Upgrade Charge:

____

____

ATTACHMENT B

Form For
Short-Term Firm and Non-Firm Point-To-Point Service Agreement

1.0 This Service Agreement, dated as of _______________, is entered into, by and between Nova Scotia Power Incorporated (the Transmission Provider), and ____________ (the Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Short-Term Firm or Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Short-Term Firm or Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

NSPI **Open Access Transmission Tariff**

Transmission Provider:

Mailing Address as posted on OASIS

Transmission Customer:

Company Name: ______________________________
Billing Contact: ______________________________
Address: ______________________________
____
Telephone: ______________________________
Fax: ______________________________
E-mail ______________________________
TSIN Code ______________________________
TSIN DUNS ______________________________
Administrative Contact: ______________________________
Address: ______________________________
____
Telephone: ______________________________
Fax: ______________________________
E-mail ______________________________

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ____________________ ____________________ ____________________

Name Title Date

Transmission Customer:

By: ____________________ ____________________ ____________________

Name Title Date

NSPI **Open Access Transmission Tariff**

ATTACHMENT C

Methodology To Assess Available Transmission Capability

1. Objective

The purpose of this document is to describe the methodology used by the Transmission Provider to determine the Total Transfer Capability (TTC) and the Available Transmission Capability (ATC) between the Transmission Provider and its neighboring utilities. The Transmission Provider is Nova Scotia Power, Inc. (NSPI), which owns, controls, and operates facilities used for the generation and transmission of electric power and energy and provides transmission services under the OATT. NSPI is also the System Operator for the electric system in Nova Scotia.

The following documents were used as references:

i. *Revised NPCC Methodology and Procedure for the Determination and Posting of Available Transfer Capability*; NPCC Ad Hoc ATC Working Group Report, Northeast Power Coordinating Council, June 2, 1998

ii. *Available Transfer Capability Definitions and Determination*; North American Electric Reliability Council, June 1996.

iii. *Basic Criteria for Design and Operation of Interconnected Power Systems*; NPCC Document A-2, Northeast Power Coordinating Council, Revised August 9, 1995.

iv. *Special Protection Systems Criteria*, NPCC Document A-11; Northeast Power Coordinating Council, November 14, 2002.

2. Transmission Interfaces

Given Nova Scotia's geographic location, interconnection with other transmission systems is provided by a single interface with New Brunswick, although there are three transmission lines crossing the NS-NB border (one 345kV and two 138kV lines). From the perspective of NS-NB transfer capability, there is a single 345kV line in parallel with a single 138kV line, since the two 138kV lines merge into a single 138kV line at Springhill Nova Scotia.

It may be necessary to calculate ATC/TTC on internal interfaces as a means of managing congestion.

3. General Outline for Evaluation of the ATC

As defined by NERC, ATC is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of Existing Transmission Commitments (ETC) (which includes retail customer service), less the Capacity Benefit Margin (CBM).

Since the Maritimes Area is radially connected to the Eastern Interconnection, and Nova Scotia is radially connected to the New Brunswick system, the calculation of ATC does not involve "parallel path flows". However, the NS-NB interconnection capability is dependent on a number of operational considerations that introduce uncertainty into the value of ATC for long-term reservation requests.

The determination of ATC and TTC requires the cooperation of the transmission providers on each side of the interconnection. NSPI and NB Power must agree on the limiting factor to establish the capacity of the interconnection in each direction. The NS-NB interconnection is limited by thermal equipment ratings and system stability for the export limit, and thermal, voltage, and stability ratings for the import limit. The interconnection capability relies heavily on the design and operation of Special Protection Systems, as defined by NPCC. Import capability is a function of the power that can be reliably delivered to the interface via the NB Power Transmission System, and the power that can reliably received into Nova Scotia. The NB Power Transmission Tariff highlights the methodology used to determine the former quantity. It should be noted that the NB Power transmission system has "simultaneous transfer limits", which means that they cannot support simultaneous transfers on multiple interfaces. The simultaneous transfers on the following interfaces impact the NS-NB transfer limits:

- New Brunswick – New England interface
- New Brunswick – Prince Edward Island interface

Load flow base cases for winter peak and summer conditions are used in the determination of seasonal and long-term TTC and ATC values. For the winter case, an in-province forecasted peak load is modeled. In the summer case, in-province forecasted load is modeled on the basis of residential/commercial load at 60% of winter peak and large industrial at 100% of winter peak. All transmission facilities are assumed to be in-service and "normal" generation dispatch patterns are modeled.

Studies are then conducted to determine the TTC values under all possible combinations of transactions as explained in Section 4. The interface TRM and the CBM are determined using the principles given in Sections 5 and 6 respectively. Firm ATC and non-firm ATC values are calculated using the set of equations given in Sections 7 and 8 respectively.

4. Procedure for Calculating TTC

Based on load flow and stability studies, normal and first contingency scenarios are analyzed to determine the TTC of each interface independent of transactions on the other interfaces.

The non-simultaneous TTC value for a given interface is defined as the lowest of the transfer limits defined by:

Thermal Limit: This is based on the most restrictive element in the transfer path (including internal Nova Scotia transmission) under normal or first contingency scenarios. Normal summer and winter thermal ratings are used under non-contingency scenarios. Emergency ratings are used for single contingency scenarios.

Voltage Limit: Network voltage will be kept in the range from 0.95 to 1.05 per unit for pre-contingency conditions, and between 0.90 and 1.07 per unit following single contingencies (10 minutes following the contingency for automatic tap changer operation).

Stability Limit: This limit is reached when further increase of a particular TTC results in system instability during normal conditions or single contingency scenarios.

Frequency Limits: If the Nova Scotia transmission system becomes isolated while importing power, frequency will decline until the load and generation balance is restored. This may require the activation of underfrequency load shedding (UFLS) in conjunction with generator governor response. The converse is true when exporting power, but limits on overfrequency are based on adverse impacts on generation. Frequency excursions for a single contingency must be maintained between 59.3 Hz and 61 Hz to avoid disruption to firm load or generating units.

NSPI uses a number of Special Protection Systems (SPS's), designed according to NPCC guidelines, to enhance the transfer limits between NSPI and NB Power. Whenever applicable, the SPS's are identified and reviewed as a part of the TTC calculations.

5. Procedure for Calculating Transmission Reliability Margin (TRM)

TRM for the NS-NB interface are determined on the basis of maintaining adequate

Operating Margin, including Reserve Pickup Margin (such as reserve sharing), and to cover uncertainties within Nova Scotia and neighboring systems. Therefore, coordination with the concerned utilities is carried out in order to arrive at TRM values that produce a set of commercially viable and reliable ATC values. The TRM values are posted on OASIS, and are used in the calculations to arrive at the ATC values. In some cases no TRM is applied because the interface is protected by SPS action.

6. Procedure for Evaluation of the Capacity Benefit Margin (CBM)

Adequacy planning for Nova Scotia is conducted in accordance with the NPCC A-2 Criteria (Basic Criteria for Design and Operation of Interconnected Power Systems). The NSPI system is designed under the assumption that CBM is applied to the NS-NB interconnection capability. Long-term reservations must respect this margin. CBM is applicable to import capacity only.

7. Procedure for Calculating the Firm ATC Values

The firm ATC value for a given interface, in a specific direction, is evaluated as follows:

1) Determine the TTC value for this interface (taking into consideration any firm simultaneous transactions on other interfaces that impact the limit of this interface).

2) List all firm transmission reservations on the given interface, and calculate the total firm transmission reservation.

3) Determine the TRM and CBM values for this interface.

4) Firm ATC = TTC – TRM – CBM – Total Firm Transmission Reservations (all terms of the ATC equation are directional).

8. Procedure for Calculating the Non-Firm ATC

The non-firm ATC value for a given interface, in a given direction, is evaluated using different equations in the operating and planning horizons, as follows:

Operating Horizon: Takes into consideration transmission schedules.

1) List all Firm Scheduled Services on the given interface, and calculate the net schedule.

2) List all Non-firm Scheduled Services on the given interface, and calculate the net schedule.

3) Determine the TTC value for this interface (taking into consideration the firm and non-firm transmission schedules on other interfaces which impact the simultaneous limit of this interface).

4) Determine the TRM and CBM values and the portion (α) of the TRM that will not be available for any transactions, because of reliability concerns, where $0 \leq \alpha \leq 1$.

5) Non-firm ATC = TTC – α (TRM) – Non-firm Transmission Schedules – Firm Transmission Schedules (all terms of the ATC equation are directional with the exception of the "net" schedule).

Planning Horizon: Beyond the operating horizon and takes into consideration the transmission reservations.

1) List all Firm Transmission Reservations on the given interface, and calculate the total Firm Reservations.

2) List all Non-firm Transmission Reservations on the given interface, and calculate the total Non-firm Reservations.

3) Determine the TTC value for this interface (taking into consideration the firm and non-firm transmission reservations on other interfaces that impact the simultaneous TTC value for this interface).

4) Determine the TRM and CBM values and the portion of (β) of the TRM, that will not be available for any transactions, because of reliability concerns, where $0 \leq \beta \leq 1$.

5) Non-firm ATC = TTC – β (TRM) – Non-firm Transmission Reservations – Firm Transmission Reservations (all terms of the ATC equation are directional).

6) Long term ATC results do not include short-term equipment outages for maintenance and emergency repairs.

9. Updating Periods for the TTC and ATC

Because the TTC and ATC values depend on system conditions, actual schedules and planned transmission reservations, it is necessary to conduct periodic reviews to ensure that the posted values take into consideration the most recent information available to the Transmission Provider. Therefore updating of the TTC and ATC values will be done according to the following guidelines:

9.1 Updating the TTC Values:

The posted seasonal (summer and winter) TTC values for the NS-NB interface (and any future posted interface), under normal conditions, will be considered constant and valid for the entire season. These will be reviewed annually to ensure their validity for future years. Actual or forecast changes in system conditions will require a review and, if necessary, revision of the impacted TTC value(s).

9.2 Updating the TRM and CBM Values:

The TRM and CBM values will be reviewed, and updated as necessary, to account for any changes in system conditions that may require new margins. As previously indicated these values will not be posted on the OASIS, but will be used in the calculation of the ATC values.

9.3 Updating the ATC Values:

The Firm and Non-Firm ATC values for the operating and planning horizons are automatically calculated for the appropriate time frame, based on the following:

- Firm Scheduled Transmission Service,
- Non-Firm Scheduled Transmission Service,
- Firm Transmission Reservations,
- Non-Firm Transmission Reservations,
- TRM and CBM values,
- The magnitudes of α & β factors that may influence the amount of TRM and CBM that is available for non-firm transactions, and
- Individual and Simultaneous TTC values.

Open Access Transmission Tariff

ATTACHMENT D

Methodology for Completing a System Impact Study

1. Scope

A System Impact Study may be performed by the Transmission Provider to determine whether the Transmission Service requested by an Eligible Customer can be accommodated using the existing Transmission System. The study will identify any system constraints or impairments that would likely occur on the Transmission System and any redispatch options, within Nova Scotia, which may be available to accommodate the requested service. The study may examine potential constraints in other Operating Areas. The System Impact Study would be performed at the Eligible Customer's expense. A System Impact Study does not evaluate options associated with facilities expansion or network upgrades. System Impact Studies related to generation interconnection are conducted pursuant to the NSPI Standard Generator Interconnection Procedures.

2. Assessment of the Need

The Transmission Provider will make an assessment whether a System Impact Study is required to determine if the requested service can be accommodated. In making this assessment, the Transmission Provider will rely on operating experience and available technical information. The Eligible Customer will be advised of the result of this assessment as follows:

1. A System Impact Study is not required because the available information is sufficient to make a decision whether to approve or reject the requested service; or

2. A System Impact Study is required before making a decision on the requested service.

3. Guidelines and Principles

In order to perform a System Impact Study, the Transmission Provider will develop system models for the known transmission system, including appropriate representation of load and generation for the time frame during which the Transmission Service is requested. These models will include existing agreements and other pending Transmission Service Requests. These models may include the representation of neighboring systems using the NPCC library of base cases as required.

The study may include load flow, short circuit, stability, loss evaluation, economic and other analyses as appropriate and will be conducted according to the following:

1. The Transmission Provider criteria and guidelines for operation and planning.

2. NPCC criteria and guidelines for design and operation of interconnected power systems.

3. NERC planning and operating standards.

4. Good Utility Practice.

4. Action Following the Completion

Based on the outcome of the System Impact Study, the Transmission Provider will notify the Eligible Customer of one of the followings findings:

1. The requested service can be accommodated without additional operating measures or new facilities.

2. There are system constraints or impairments that may be avoided by system re-dispatch within Nova Scotia. The Eligible Customer is responsible for any additional cost incurred as a result of implementing such re-dispatch options.

3. The requested service can be accommodated by changing the operating procedures and/or securing Transmission Service in another Operating Area. The Eligible Customer shall be responsible for contacting the other Operating Area to determine the general availability of such operating procedures or services.

4. The requested service cannot be accommodated because of equipment limitations or it can cause unacceptable system performance or reliability risks. The Eligible Customer can decide whether to modify or cancel the request.

NSPI **Open Access Transmission Tariff**

ATTACHMENT E

Standards of Conduct

Nova Scotia Power Inc.

STANDARDS OF CONDUCT

For the Provision of Wholesale and Renewable to Retail Electric Transmission Service

These Standards of Conduct are applicable to Nova Scotia Power and its employees and the employees of its Affiliates. These Standards of Conduct govern Nova Scotia Power's relationships with its transmission customers and potential customers, including employees of Nova Scotia Power and its Affiliates.

These Standards of Conduct are based on FERC Order 2004 and its subsequent re-hearings and clarifications. Order 889 was issued in conjunction with FERC Order 888 regarding non-discriminatory transmission open access; Order 2004 further clarifies Order 889.

DEFINITIONS:

Affiliate: For the purposes of these Standards of Conduct, the term "affiliate" shall be interpreted in accordance with Sections 2(2), 2(3), and 2(4) of the Nova Scotia Companies Act 1.

1 **Deemed affiliate**
2(2) A company shall be deemed to be an affiliate of another company if one of them is the subsidiary of the other or if both are subsidiaries of the same company or if each of them is controlled by the same person.
Deemed control
2(3) A company shall be deemed to be controlled by another person or by two or more companies if

Energy Control Centre: means the facilities located in Halifax, Nova Scotia, which are used by the transmission services scheduling agent, the Operating Area operator, the bulk transmission system operator and the real time generation dispatch group for the Nova Scotia Power integrated system.

Marketing, Sales or Brokering: means a sale for resale of electric energy. Sales and Marketing employee or unit includes Nova Scotia Power's energy sales unit, unless such unit engages solely in bundled retail sales.

Open Access Same-time Information System (OASIS): An electronic medium information system, which provides Open Access Transmission customers with relevant information regarding available transmission capacity, prices, and other matters to enable them to obtain open access non-discriminatory transmission services from the Transmission Provider.

Operating Area: means the Nova Scotia transmission system, bounded by the Nova Scotia – New Brunswick border, under the control of the Nova Scotia Power Energy Control Centre. The Nova Scotia Operating Area is a part of the Maritimes Control Area as defined by the Northeast Power Coordinating Council.

Transmission: means electric transmission, network or point-to-point service, reliability service, ancillary services or other methods of transportation or the interconnection with jurisdictional transmission facilities.

(a) voting securities of the first-mentioned company carrying more than fifty per cent of the votes for the election of directors are held, otherwise than by way of security only, by or for the benefit of the other person or by or for the benefit of the other companies; and

(b) the votes carried by such securities are entitled, if exercised, to elect a majority of the directors of the first-mentioned company.

Deemed subsidiary

2(4) A company shall be deemed to be a subsidiary of another company if

(a) it is controlled by

(i) that other, or

(ii) that other and one or more companies each of which is controlled by that other, or

(iii) two or more companies each of which is controlled by that other; or

Transmission Customer: means any eligible customer, or designated agent that can or does execute a transmission service agreement or can or does receive transmission service, including all persons who have pending requests for transmission service or for information regarding transmission.

Transmission Function Employee: means an employee, contractor, consultant or agent of Nova Scotia Power who conducts transmission system operations or reliability functions, including, but not limited to, those who are engaged in day-to-day duties and responsibilities for planning, directing, organizing or carrying out transmission-related operations.

Transmission System Operations or Reliability Functions: means the direct act of operating the Nova Scotia transmission system to provide transmission services according to an approved transmission tariff and the reliability rules of the Northeast Power Coordinating Council.

Transmission System: The facilities owned, controlled or operated by Nova Scotia Power that are used to provide transmission service under the Tariff.

A. GENERAL RULES:

1. Transmission Function employees must function independently of Nova Scotia Power's Marketing and Sales employees, and from any employees of its Affiliates.

2. Transmission Function employees must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and must not operate its transmission system to preferentially benefit an Affiliate.

(b) it is a subsidiary of a company that is that others subsidiary. R.S., c. 81, s. 2; 1990, c.15, s. 2.

B. INDEPENDENT FUNCTIONING:

1. **Separation of Functions**

a) Except in emergency circumstances affecting system reliability, Transmission Function Employees must function independently of Nova Scotia Power's Marketing and Sales or Affiliates' employees.

b) Notwithstanding any other provisions in this section, in emergency circumstances affecting system reliability, Transmission Function Employees must post on the OASIS each emergency that resulted in any deviation from the standards of conduct, within 24 hours of such deviation.

c) Employees of Nova Scotia Power's Affiliates or Marketing and Sales function are prohibited from:

i) conducting Transmission System Operations or Reliability Functions; and

ii) having access to the Energy Control Centre, or similar facilities used for Transmission System Operations or Reliability Functions, that differs in any way from the access available to other Transmission Customers.

d) Nova Scotia Power is permitted to share support employees and field and maintenance employees with their Marketing and Affiliates.

2. **Identifying Affiliates on the Public Internet**

a) Nova Scotia Power must post the names and addresses of its Marketing and Sale units and Affiliates on its OASIS.

b) Nova Scotia Power must post on its OASIS a complete list of the facilities shared by Transmission Function Employees and employees of its Marketing and Sales units or Affiliates, including the types of facilities shared and their addresses.

c) Nova Scotia Power must post comprehensive organizational charts showing:

i) The organizational structure of the parent corporation with the relative position in the corporate structure of the Transmission Function, Marketing and Sales units and any Affiliates;

ii) For Nova Scotia Power's Transmission Function, the business units, job titles and descriptions, and chain of command for all positions, including officers and directors, with the exception of clerical, maintenance, and field positions. The job titles and descriptions must include the employee's title, the employee's duties, whether the employee is involved in transmission or sales, and the name of the supervisory employees who manage non-clerical employees involved in transmission or sales.

iii) For all employees who are engaged in Transmission Functions for Nova Scotia Power and Marketing and Sales functions, or who are engaged in Transmission Functions for Nova Scotia Power and are employed by any of the Affiliates, Nova Scotia Power must post the name of the business unit within the Marketing and Sales unit or the Affiliate, the organizational structure in which the employee is located, the employee's name, job title and job description in the Marketing and Sales unit or Affiliate, and the employee's position within the chain of command of the Marketing and Sales unit or Affiliate.

iv) Nova Scotia Power must update the information on its OASIS, required by Section B (2), (a), (b) and (c) within seven business days of any change, and post the date on which the information was updated.

v) Nova Scotia Power must post information concerning potential merger partners as Affiliates within seven days after the merger is announced.

d) **Transfers**

Transmission Function Employees and employees of Nova Scotia Power's Marketing and Sales units or Affiliates are not precluded from transferring among such functions as long as such transfer is not used as a means to circumvent these Standards of Conduct. Notices of any employee transfers must be posted on the OASIS. The information to be posted must include: the name of the transferring employee, the respective titles held while performing each function (i.e. on behalf of the Transmission Function, Marketing and Sales function or Affiliate), and the effective date of the transfer. The information posted under this section must remain on the OASIS for 90 days.

e) **Written Procedures**

i) Nova Scotia Power must post on the OASIS current written procedures for implementing the Standards of Conduct in sufficient detail to enable customers to determine that Nova Scotia Power is in compliance with the Standards of Conduct.

ii) Nova Scotia Power will distribute the written procedures to all its employees and employees of its Affiliates.

iii) Nova Scotia Power shall require all applicable employees, covered by the Standards of Conduct, to attend training and sign a document certifying that they have been trained regarding the requirements of the Standards of Conduct.

iv) Nova Scotia Power shall designate a Chief Compliance Officer who will be responsible for Standards of Conduct compliance.

3. **Non-discrimination requirements**

a) **Information Access**

i) Employees of Nova Scotia Power engaged in Marketing and Sales or any employee of an Affiliate may have access only to information which is available to Nova Scotia Power's transmission customers (i.e., the information posted on the OASIS), and must not have access to any information about Nova Scotia Power's transmission system that is not available to all users of the OASIS.

ii) Nova Scotia Power must ensure that any employee who is engaged in Marketing and Sales or any employee of an Affiliate is prohibited from obtaining information about Nova Scotia Power's transmission system (including, but not limited to, information about available transmission capability, price, curtailments, ancillary services, balancing, maintenance activity, capacity expansion plans or similar information) through access to information not posted on the OASIS or that is not otherwise also available to the general public without restriction.

NSPI **Open Access Transmission Tariff**

b) **Prohibited Disclosure**

i) Transmission Function Employees may not disclose to Nova Scotia Power's Marketing and Sales employees, or to employees of Affiliates any information concerning the transmission system of Nova Scotia Power or the transmission system of another (including, but not limited to, information received from non-affiliates or information about available transmission capability, price, curtailments, storage, ancillary services, balancing, maintenance activity, capacity expansion plans, or similar information) through non-public communications conducted off the OASIS that are not contemporaneously available to the public, or through information on the OASIS that is not at the same time publicly available.

ii) Transmission Function Employees may not share any information, acquired from nonaffiliated transmission customers or potential nonaffiliated transmission customers, or developed in the course of responding to requests for transmission or ancillary service on the OASIS, with employees of its Marketing and Sales unit or Affiliates, except to the limited extent information is required to be posted on the OASIS in response to a request for transmission service or ancillary services.

iii) If a Transmission Function Employee discloses information in a manner contrary to the requirements of s. B, 3(b), (i) or (ii) Nova Scotia Power must immediately post such information on the OASIS.

iv) A non-affiliate transmission customer may voluntarily consent, in writing, to allow Nova Scotia Power's Transmission Function to share the non-affiliated customer's information with Marketing and Sales or an Affiliate.

v) Nova Scotia Power is not required to contemporaneously disclose to all transmission customers or potential transmission customers information covered by s. B, 3(b), (i) if it relates solely to a Marketing and Sales or an Affiliate's specific request for transmission service.

vi) Nova Scotia Power's Transmission Function may share generation information necessary to perform generation dispatch with its Marketing and Sales units and Affiliates that does not include specific information about individual third party transmission transactions or potential transmission arrangements.

vii) Transmission Function Employees are not permitted to use anyone as a conduit for sharing information covered by the prohibitions of s. B, 3(b), (i) or (ii) with Marketing and Sales or an Affiliate.

viii) Nova Scotia Power is permitted to share crucial operating information with its Affiliate to maintain the reliability of the transmission system.

c) **Implementing Tariffs**.

i) Transmission Function Employees must strictly enforce all tariff provisions relating to open access transmission service if these tariff provisions do not permit the use of discretion.

ii) Transmission Function Employees must apply all tariff provisions relating to open access transmission service in a fair and impartial manner that treats all transmission customers in a non-discriminatory manner if these tariff provisions permit the use of discretion.

iii) Transmission Function Employees must process all similar requests for transmission in the same manner and within the same period of time.

iv) Nova Scotia Power must maintain a written log detailing the circumstances and manner in which it exercised its discretion under any terms of the tariff. The information contained in this log is to be posted on the OASIS within 24 hours of when Nova Scotia Power's Transmission Function exercises its discretion under any terms of the tariff.

v) Nova Scotia Power may not, through its tariffs or otherwise, give preference to its own Marketing and Sales function or to any Affiliate, over any other wholesale customer in matters relating to the sale or purchase of transmission service (including, but not limited to, issues of price, curtailments, scheduling, priority, ancillary services, or balancing).

d) **Discounts**

Any offer of a discount for any transmission service made by Nova Scotia Power must be posted on the OASIS contemporaneously with the time that the offer is contractually binding. The posting must include: the name of the customer involved in the discount and whether it is an affiliate or whether an affiliate is involved in the transaction, the rate offered; the maximum rate, the time period for which the discount would apply; the quantity of power or gas scheduled to be moved; the delivery points under the transaction; and any conditions or requirements applicable to the discount. The posting must remain on the OASIS for 60 days from the date of posting.

ACKNOWLEDGEMENT

I acknowledge that I have read the Standards of Conduct that functionally separate the Transmission System Operations and Reliability Functions from the Marketing, Sales and Affiliates Functions and I agree to comply fully with them.

____

Name

____

Signature

NSPI **Open Access Transmission Tariff**

ATTACHMENT F

Service Agreement For
Network Integration Transmission Service

1.0 This Service Agreement, dated as of ____________________, is entered into, by and between Nova Scotia Power Incorporated (the Transmission Provider), and ____________________________________ (the Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Network Integration Transmission Service in accordance with the provisions of Section 29.2 the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in the amount of $____________, in accordance with the provisions of Section 29.2 of the Tariff.

4.0 Service under this agreement shall commence on the later of

(1) _______________, or

(2) the date on which construction of all Interconnection Equipment, any Direct Assignment Facilities and/or Network Upgrades are completed, or

(3) the date on which a Network Operating Agreement is executed and all requirements of said Agreement have been completed or

(4) the date the Board approves providing the service, if applicable

Service under this agreement shall terminate on ____________________.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Integration Service in accordance with the provisions of Part III of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Mailing Address as posted on OASIS

Transmission Customer:

Company Name: ____

Billing Contact: ____

Address: ____

____

Telephone: ____

Fax: ____

E-mail ____

TSIN Code ____

TSIN DUNS ____

Administrative Contact:____

Address: ____

____

Telephone: ____

Fax: ____

E-mail ____

NSPI **Open Access Transmission Tariff**

7.0 Term of Transaction:

____

Start Date:

____

Termination Date:

____

8.0 A detailed description of power and energy to be transmitted by Transmission Provider.

____

____

____

9.0 Detailed description of each Network Resource, including any operating restrictions:

____

____

____

10.0 Detailed description of the Transmission Customer's anticipated use of NSPI's interfaces:

____

____

____

11.0 Description of any transmission system owned or controlled by the Transmission Customer:

____

____

____

NSPI **Open Access Transmission Tariff**

12.0 Name (s) of any Intervening Transmission providers:

____
____
____

13.0 The Network Integration Service Customer's obligation for the following services will be provided as follows:

	Ancillary Service	**Source**
1.	Scheduling, System Control and Dispatch	NSPI
2.	Reactive Supply and Voltage Control	NSPI
3.	Regulation and Frequency Response:	
	3a. Regulation	__________
	3b. Load Following	__________
4.	Energy Imbalance	__________
5.	Operating Reserve - Spinning Reserve	__________
6.	Operating Reserve	
	6a. Supplemental (10-minute) Reserve	__________
	6b. Supplemental (30 Minute) Reserve	__________

The Transmission Provider will confirm the acceptability of each source of supply proposed by the Transmission Customer.

14.0 Description of required Direct Assignment Facilities:

____
____
____

NSPI **Open Access Transmission Tariff**

15.0 In addition to the charge for Transmission Service and charges for Ancillary Services as set forth in the Tariff, the customer will be subject to the following charges:

15.1 System Impact and/or Facilities Study Charge (s):

____

____

15.2 Direct Assignment Facilities Charges:

____

____

15.3 Redispatch Charges:

____

____

15.4 Network Upgrade Charges:

____

____

16.0 Credit for Network Customer Owned Transmission Facilities will apply in accordance with Section 30.9 of the Tariff.

17.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ______________________ ______________________ ______________________

Name Title Date

Transmission Customer:

By: ______________________ ______________________ ______________________

Name Title Date

NSPI **Open Access Transmission Tariff**

ATTACHMENT G

Network Operating Agreement

Applicability

The Network Operating Agreement applies to Network (and Point-to-Point) Loads that are physically connected to the NSPI transmission system.

Network Customers that are not physically connected to the NSPI transmission system will be governed by the interconnection agreement between NSPI and the transmission owner to which the Network Customer is physically connected.

NETWORK OPERATING AGREEMENT

Between

NOVA SCOTIA POWER INCORPORATED

And

____
(Insert Customer Name)

____
(Date)

NETWORK OPERATING AGREEMENT

THIS AGREEMENT MADE THIS __________ day of ____________________, 20_____.

BETWEEN: NOVA SCOTIA POWER INCORPORATED

a body corporate, with head office at Halifax, Province of Nova Scotia, hereinafter referred to as "NSPI";

- and –

____________________________________,

and Eligible Customer, in accordance with Section 1.14 of NSPI's Open Access Transmission Tariff, having its head office in _______________________ , hereinafter referred to as "the Customer",

Deleted: 11

Both of which may hereinafter be referred to as "the Parties hereto".

WHEREAS the Customer is the owner and operator of facilities located in ___________, the County of _______________________ in the Province of Nova Scotia (the "Customer's premises"), and requires a supply of power and energy for its operation;

AND WHEREAS NSPI has agreed to deliver and the Customer has agreed to purchase from NSPI transmission services for aforesaid Customer premises pursuant to the terms and conditions of this Agreement.

NOW THEREFORE this Agreement witnesseth that in consideration of the premises and the mutual covenants and agreements hereinafter set forth, the Parties hereto mutually covenant and agree as follows:

NSPI **Open Access Transmission Tariff**

1.0 DEFINITIONS

In this Agreement, unless the context otherwise requires, the following definitions shall apply:

NSPI Facilities

NSPI Facilities are the transmission system of NSPI and the necessary ________ kV extension thereof constructed to the Delivery Point, together with the Metering Equipment, all of which are provided, owned and maintained by NSPI.

Customer Facilities

The Customer Facilities are the facilities beyond the Delivery Point, which are provided, owned and maintained by the Customer and, in addition, shall be deemed to also include any Rental Facilities.

Without limiting the generality of the foregoing, these facilities include

____

____

____

Delivery Point

The Delivery Point is the place at which the Customer Facilities and NSPI Facilities are connected together, specifically ____ as shown on NSPI Substation Diagram No. ________________ dated ______________________________ attached hereto and marked Appendix A.

Good Utility Practice

Good Utility Practice is a practice consistent with the reasonable and practicable operation of electric utilities in Canada.

Metering Equipment

The Metering Equipment is the meters and associated equipment approved by Measurement Canada or such other authority as may from time to time be charged with such responsibility, required for measuring power and energy supplied to the Customer under this Agreement.

Metering Point

The Metering Point is the point at which all power and energy supplied to the Customer is measured. The Metering Point is at or near the Delivery Point.

Rental Facilities

The Rental Facilities are those facilities provided, owned and maintained by NSPI for which the Customer pays a Rental Charge.

Without limiting the generality of the foregoing, these facilities include

2. 0 CHARACTERISTICS OF SUPPLY

2.1 Characteristics of Supply

Subject to Article 3.1 hereof the power and energy supplied to the Customer at the Delivery

Point shall be three-phase alternating current at the nominal frequency of 60-hertz and at a nominal voltage of ______________________ volts between phases.

2.2 Metering

Metering shall be in accordance with NSPI's "Metering Standards" and Section 4 "Metering" of NSPI's "Rates / Regulations and Procedures". Meter reading and billing shall be in accordance with Section 5 "Meter Reading and Billing" of NSPI's "Rates / Regulations and Procedures".

NSPI shall provide, own and maintain the Metering Equipment. If requested by NSPI, the Customer shall provide at the Customer's expense adequate space and facilities on the Customer's premises satisfactory to NSPI for the installation and maintenance of the Metering Equipment.

In this section where reference is made to Measurement Canada it shall also be deemed to include any other authority as may from time to time be charged with the responsibility for metering.

If, for any period, the Metering Equipment or any part thereof is not in service, the power and energy supplied during such period shall be determined by NSPI, after consultation with the Customer, from the best information available. In the event that the Parties are unable to reach agreement on the determination of the power and energy supplied to the Customer, the decision of NSPI shall be deemed to be conclusive.

The Customer may request NSPI to verify the accuracy of the Metering Equipment more often than once a year. If the Customer is not satisfied with NSPI's results the Customer may request that further verification be made by Measurement Canada. In either case, if the Metering Equipment is accurate within the limits specified by Measurement Canada, the Customer shall pay the cost of performing such verification. If the Metering Equipment is inaccurate by more than the limits specified by Measurement Canada, an adjustment based on the full error of the Metering Equipment shall be made in the Customer's bills for any known or agreed period of inaccuracy.

If, at any time, the Metering Equipment is found to be inaccurate by more than the limits specified by Measurement Canada, the Metering Equipment or any faulty components thereof shall be promptly replaced, repaired or readjusted by NSPI at NSPI's expense.

NSPI may modify or replace the Metering Equipment from time to time.

3.0 GENERAL OBLIGATIONS OF THE CUSTOMER

3.1 Customer's Equipment

The Customer shall be responsible for installing and maintaining protective equipment to protect the Customer Facilities from variations in frequency and voltage or from temporary delivery of other than three-phase power.

The Customer agrees that all motors, transformers and other equipment utilized in its installation shall conform with Canadian Standards Association requirements, and shall be wired, connected and operated so as not to produce detrimental effects on NSPI Facilities which could adversely affect the adequacy of service to the Customer and other customers.

3.2 Electrical Harmonics

Electrical harmonics shall be considered as components of current or voltage whose frequency is some multiple of the 60-hertz fundamental frequency. The Customer shall assume the responsibility of direct loss by reason of damages to NSPI Facilities caused by electrical harmonics produced in the Customer Facilities provided that such liability shall be restricted to the repair or, if necessary, the replacement or modification of such NSPI

Facilities which have been damaged or made necessary by reason of electrical harmonics produced in the Customer Facilities. The Customer agrees to take all reasonable steps to limit the effects of any electrical harmonics that may be produced in the Customer Facilities to a level tolerable to NSPI. NSPI shall cooperate with the Customer in the investigation of any harmonic problems and the analysis of corrective measures. NSPI reserves the right to discontinue the supply of power and energy where in its opinion the reliability of NSPI Facilities is threatened by the presence of electrical harmonics.

3.3 Load Balance

The Customer agrees to take and use the three-phase current supplied through the NSPI transmission system in such manner that in no case shall the difference between any two phases be greater than 5%. The Customer, upon written instructions from NSPI, shall so adjust its load as to comply with this requirement.

3.4 Right-of-Way

The Customer agrees to provide and arrange for the necessary right-of-way on the Customer's premises for the appropriate NSPI Facilities and Rental Facilities free of cost to NSPI during the continuance of this Agreement, renewal or renewals thereof, and for six months thereafter, so that NSPI, its subcontractors, their respective employees and agents may enter upon the same and build, install and erect, construct, operate, repair and remove any or all of the appropriate NSPI Facilities or Rental Facilities, all of which shall not unduly interfere with the Customer's operations and which in the opinion of NSPI are necessary for the delivery of transmission service under this Agreement. Any changes, which the Customer may request NSPI to make in the location of NSPI Facilities or Rental Facilities, shall be made at the expense of the Customer.

3.5 Right of Access

One or more representatives of NSPI appointed for this purpose may, at any reasonable time during the continuance of this Agreement, have access to the Customer's premises for the purposes of but not limited to meter reading, inspection, operation, testing, adjustment, repair, alteration, reconstruction, and removal of NSPI Facilities, or for the purpose of inspecting the Customer Facilities and taking records there from as required for compliance with this Agreement.

3.6 Preparation for the Receipt of Transmission Service

The Customer agrees to prepare for the receipt and use of transmission services hereunder and to supply, erect and maintain at its own risk, cost and charge, all transformers, switchgear, protective equipment, as well as poles, wires, hardware, cables, fittings, insulators and materials used in distribution on the Customer's premises beyond the Delivery Point.

In addition to the foregoing, the Customer agrees to provide, own and maintain beyond the Delivery Point any equipment that NSPI deems necessary from time to time during the continuance of this Agreement for the safety and security of operation of NSPI Facilities in accordance with Good Utility Practice. All the said equipment of the Customer shall be subject to the approval of NSPI and shall be installed, maintained and operated in a manner satisfactory to NSPI.

3.7 Customer's Responsibility for NSPI Facilities on its Premises

All NSPI Facilities and Rental Facilities furnished and installed on the Customer's premises shall remain the property of NSPI and should such NSPI Facilities or Rental Facilities be destroyed or damaged from any cause due to the Customer, or from any peril originating on the Customer's premises, the Customer shall reimburse NSPI for the full cost of repair or replacement.

3.8 Insulation Contamination

Contaminants shall be considered as foreign matter or substance deposited on insulation components which reduce the value and effectiveness of the insulation and may consist of dust, particles or chemicals either dry or in solution.

The Customer shall be responsible for the correction of contamination problems occurring on the Customer Facilities. If contaminants caused by activities on the Customer's premises accumulate on NSPI Facilities, which, in the opinion of NSPI affect the insulating characteristics, the Customer shall bear the cost of removal of contamination or replacement of insulation components as deemed necessary by NSPI. Interruptions of service occasioned to correct contamination problems shall be, where possible, arranged at a time mutually agreeable to the Customer and NSPI. Notwithstanding the above NSPI reserves the right to discontinue the supply of power and energy at its discretion where the reliability of its system is threatened by the presence of contaminants on insulation components.

4.0 GENERAL RIGHTS AND OBLIGATIONS OF NSPI

4.1 Interruption of Supply

NSPI shall provide a regular and uninterrupted delivery of transmission services under the terms of this Agreement but shall have no liability to the Customer for loss or damage from any failure of delivery in respect of any abnormality, delay, interruption or other partial or complete failure in the said delivery when such loss or damages are caused by something that is beyond the ability of NSPI to control by reasonable and practicable effort, said effort to be measured by Good Utility Practice as defined herein.

NSPI shall have the right to suspend the delivery of transmission services for the purpose of safeguarding life or property, for making repairs, changes, renewals, improvements or replacements to NSPI Facilities or Rental Facilities but all such interruptions shall be of a minimum duration consistent with the exigencies of the case, and when possible, arranged for a time least objectionable to the Customer, and such interruptions shall not release the Customer from its obligation to pay all charges pursuant to this Agreement during the period of any such suspensions and to resume the use of power and energy when the supply is restored. When such repairs, changes, renewals, improvements or replacements are of a non-emergency routine nature that can be scheduled in advance by NSPI, NSPI shall advise the Customer in writing at least two weeks in advance of such work. The Customer shall be responsible for any additional costs incurred by NSPI resulting from performing, at the Customer's request, such repairs, changes, renewals, improvements or replacements outside of normal working hours.

4.2 Special or Consequential Damages

Notwithstanding any other provision in this contract, NSPI shall not be liable to the Customer for special or consequential damages, or damages for loss of use, arising directly or indirectly from any breach of this contract, fundamental or otherwise, and in particular but not limited to interruption of supply or from any acts or omissions of its employees.

4.3 Removal of Equipment at Termination

NSPI shall, at the termination of this Agreement, or within six months thereafter, remove from the Customer's premises the appropriate NSPI Facilities and Rental Facilities which may have been installed by NSPI for the supply of power and energy under this Agreement. Notwithstanding the termination of this Agreement, until such time as the NSPI Facilities and Rental Facilities are removed, they remain the risk of the Customer, but after the expiration of said six months period all such NSPI Facilities and Rental Facilities shall be at the risk of NSPI.

5.0 ENVIRONMENTAL CONTAMINATION

5.1 Environmental Contamination

The Customer shall comply with all environmental laws and regulations with respect to Customer Facilities.

The Customer shall indemnify and save harmless NSPI from all loss, expense, damage or injury to persons or property inclusive of NSPI property arising as a result of environmental damage, contamination and/or injury due to or caused by the Customer.

NSPI shall comply with all environmental laws and regulations with respect to NSPI Facilities.

NSPI shall indemnify and save harmless the Customer from all loss, expense, damage or injury to persons or property inclusive of Customer property arising as a result of environmental damage, contamination and/or injury due to or caused by NSPI.

Both parties agree to immediately notify the other of any environmental incident that occurs relative to the terms of this Agreement.

6.0 FORCE MAJEURE

6.1 Force Majeure

Force Majeure is any cause beyond the reasonable control of NSPI including, without limiting the generality of the foregoing, failure of facilities, flood, earthquake, storm, nuclear disaster, lightning, fire, epidemic, war, riot, civil disturbance, labour trouble, strike, sabotage and restraint by court or public authority which by exercise of Good Utility Practice NSPI could not be expected to avoid. If NSPI is rendered unable to fulfill any obligations by reason of Force Majeure, it shall be excused from performing to the extent it is prevented from so doing but it shall exercise Good Utility Practice to correct such inability with all reasonable dispatch, and it shall not be liable for injury, damage or loss resulting from such inability. However, settlement of strikes and labour disturbances shall be wholly within the discretion of NSPI.

7.0 INDEMNITY

7.1 Indemnity by the Customer

The Customer shall indemnify and save harmless NSPI from all loss, damage or injury to persons or property sustained by any third person or persons, including employees of NSPI and the Customer, arising from the operation and maintenance of the Customer Facilities, unless such loss, damage or injury results from negligence or willful misconduct of NSPI, its agents, servants or employees, provided that the Customer shall be given prompt notice of any such claim and shall have the exclusive right to defend and settle any such claim with the full cooperation of NSPI in such defense.

7.2 Indemnity by NSPI

NSPI shall indemnify and save harmless the Customer from all loss, damage or injury to persons or property sustained by any third person, or persons, including employees of the Customer and NSPI, arising from the operation and maintenance of NSPI Facilities, unless such loss, damage or injury results from negligence or willful misconduct of the Customer, its agents, servants or employees, provided that NSPI shall be given prompt notice of any such claim and shall have the exclusive right to defend and settle any such claim with the full cooperation of the Customer in such defense.

8.0 TERM OF AGREEMENT

8.1 Term of Agreement

The Initial Term of this Agreement shall commence on the day and year first above written and continue in force for a period of five years. This Agreement shall terminate on the expiration of the Initial Term provided one of the Parties hereto has given at least 12 months written notice to the other Party. Should neither of the Parties hereto give notice to terminate this Agreement at the expiration of the Initial Term, this Agreement shall continue in full force and effect provided however that it may be terminated at any time after the expiration of the Initial Term by either Party having first given at least 12 months written notice of termination to the other Party.

9.0. FORMER AGREEMENTS

9.1 Former Agreements

This Agreement and all attached schedules constitute the entire agreement between the parties to this Agreement pertaining to the subject matter hereof and supercedes all prior and contemporaneous agreements, understandings, negotiations and discussions whether oral or written, of the parties and there are not warranties, representations or other agreements between the parties in connection with the subject matter of this Agreement except as specifically set forth herein.

10.0 SUCCESSORS OF PARTIES

10.1 Successors and Assigns

This Agreement shall extend to and be binding upon and endure to the benefit of the Parties hereto and their respective successors and permitted assigns. The obligations under and the benefit of this Agreement shall not be assignable by either party without the consent in writing of the other party. Such consent shall not be unreasonably withheld.

11.0 MODE OF DELIVERY

11.1 Mode of Delivery

Except as provided by this Agreement or otherwise agreed from time to time, any notice or other communication which is required by this Agreement to be given in writing, shall be sufficiently given if delivered personally to a senior official of the Party for whom it is intended or faxed or e-mailed or sent by registered mail, addressed as follows:

a) In the case of the Company, to:

Attention:

b) In the case of NSPI, to:
Nova Scotia Power Incorporated
P.O. Box 910
Halifax, NS B3J 2W5
Attention: Secretary and General Counsel

or delivered to such other person or faxed or e-mailed or sent by registered mail to such other address as either Party may designate for itself by notice given in accordance with this Section.

Any notice or other communication so mailed shall be deemed to have been received on the fifth business day following the day of mailing or if faxed or e- mailed shall be deemed to have been received on the same business day as the date of the fax or e-mail or if delivered personally shall be deemed to have been received on the date of delivery.

12.0 ADMENDMENT

12.1 Amendment

If at any time during the continuance of this Agreement the parties shall deem it necessary or expedient to make any alteration or addition to this Agreement it shall be done by way of a written agreement which shall be supplemental and form part of this Agreement.

13.0 SEVERANCE

13.1 Severance

It is intended that all provisions of this Agreement shall be fully binding and effective between the parties, but in the event that any particular provision or provisions or a part of one is found void, voidable or unenforceable for any reason whatsoever, then the particular provision or provisions or part of the provision shall be deemed severed from the remainder of this Agreement and all other provisions shall remain in full force.

14.0 GOVERNING LAW

14.1 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of Nova Scotia and any applicable Federal laws.

IN WITNESS WHEREOF the Parties hereto have caused their corporate seals to be hereto affixed and these presents to be executed by their duly authorized officers respectively.

NOVA SCOTIA POWER INCORPORATED (CUSTOMER)

______________________________ ______________________________

Date:_________________________ Date:_________________________

RENEWABLE TO RETAIL MARKET TRANSITION TARIFF
Renewable to Retail

PURPOSE

Pursuant to Section 3G(2) of the Electricity Act (Nova Scotia), this Renewable to Retail Market Transition Tariff (RTT) is designed to recover from Licenced Retail Suppliers (LRS) NS Power's embedded fixed costs and deferred costs, recovered through Bundled Service, which are not otherwise recovered through other tariffs applicable to the LRS or its RtR Customers. For certainty, for the purposes of this RTT, NS Power's embedded fixed costs include, but are not limited to, generation related fixed costs (e.g. depreciation, cost of financing including return on common equity, income tax and OM&G). Deferred costs of NS Power are those costs approved by the Nova Scotia Utility and Review Board (Board) for recovery by NS Power from customers at a future date.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

APPLICABILITY

1. The RTT is applicable to the LRS, and is in addition to (and not in substitution of) any charges owing by the LRS to NS Power under the Open Access Transmission Tariff (OATT), the Standby Service Tariff or the Energy Balancing Service Tariff.

2. The RTT employs certain usage determinants and rate components applicable under both the Standby Service Tariff and the Energy Balancing Service Tariff.

3. Energy Charges and Demand Charges (both as set out below) under this RTT include provision for mitigation in respect of forecasted NS Power savings enabled by the LRS's supply of electricity to its RtR Customers. The savings credits will be determined annually on the basis of experience and will be applied on a prospective basis.

4. The Energy Charge under this RTT includes provision for annual adjustment on a prospective basis to account for the forecasted difference between NS Power's average avoided cost by the LRS's supply of electricity and its average system fuel cost. If the average avoided cost exceeds the average system fuel cost, this adjustment will be a reduction in the Energy Charge; if the average avoided cost is less than the average system fuel cost, this adjustment will be an addition to the Energy Charge.

5. An LRS taking service under this RTT shall also take service under the OATT, the Standby Service Tariff, and the Energy Balancing Service Tariff.

RENEWABLE TO RETAIL MARKET TRANSITION TARIFF
Renewable to Retail

ENERGY CHARGE

Energy charge is made up of the following components:

Energy Charge Components	**Cents per kWh**
Fixed Cost Adder from Energy Balancing Service Tariff	3.309
Annually Adjusted Energy Savings Credit	-
Annual Energy Cost Adjustment	-
Total	3.309

The Energy Charge is applicable to the LRS's monthly displaced energy on NS Power's generation system, defined as the total monthly LRS load, including distribution losses, minus the total monthly LRS top-up quantity as determined under the Energy Balancing Service Tariff for that LRS.

DEMAND CHARGE

Demand Charge is made up of two components:

Demand Charge Components	**Dollars per kW**
Demand Charge from Standby Service Tariff	$5.370
Annually Adjusted Demand Savings Credit	$0.000
Total	$5.370

The Demand Charge is applicable to the LRS's monthly displaced demand on NS Power's system determined as the difference between Winter Peak Firm Demand, in respect of the monthly bill of the LRS, and Monthly Standby Contract Demand, both as determined under the Standby Service Tariff for that LRS. For greater certainty, Winter Peak Firm Demand and Monthly Standby Contract Demand are as set out in the Standby Service Tariff.

SPECIAL CONDITIONS

(1) Nothing contained in this RTT or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this RTT, the Standby Service Tariff or the Energy Balancing Service Tariff.

Bundled Service Market / RENEWABLE TO RETAIL MARKET

	Bundled Service Market – Usage		Bundled Service Market – Revenue		Distribution – Usage		Distribution – Revenue	
	Customers	MWh	Amount	Cents/kWh	Customers	MWh	Amount	Cents/kWh
January	429	7,265	$802,132	11.04	429	7,265	$67,183	0.9
February	678	7,027	$805,268	11.46	678	7,027	$76,290	1.1
March	969	8,062	$908,900	11.27	969	8,062	$88,295	1.1
April	1199	8,058	$922,884	11.45	1,199	8,058	$93,799	1.2
May	1411	8,597	$969,658	11.28	1,411	8,597	$97,955	1.1
June	1629	8,472	$978,803	11.55	1,629	8,472	$103,921	1.2
July	1926	9,576	$1,094,816	11.43	1,926	9,576	$116,035	1.2
August	2144	10,091	$1,156,840	11.46	2,144	10,091	$124,782	1.2
September	2442	15,167	$1,719,610	11.34	2,442	9,806	$135,516	1.4
October	2772	15,558	$1,738,920	11.18	2,772	10,331	$145,535	1.4
November	3006	15,871	$1,797,183	11.32	3,006	10,727	$158,882	1.5
December	3357	15,763	$1,884,693	11.96	3,357	11,348	$193,964	1.7
TOTAL		129,506	$14,779,707	11.41		109,360	$1,402,157	1.3

	OATT – Usage			OATT – Revenue		ENERGY BALANCING SERVICE – Load (MWh)			Spill (MWh)	
	LRS	MWs	MWh	Amount	Cents/kWh	RtR Direct Delivery	Top-up	Total	Total	Net of Top-up
January	1	13.2	7,459	$94,143	1.26	5,627	1,832	7,459	7,176	5,344
February	1	14.2	7,238	$95,786	1.32	4,931	2,307	7,238	4,125	1,817
March	1	14.7	8,341	$100,539	1.21	5,295	3,046	8,341	4,201	1,154
April	1	15.5	8,294	$107,985	1.30	4,939	3,355	8,294	4,671	1,316
May	1	15.6	8,890	$106,079	1.19	4,048	4,842	8,890	2,910	(1,932)
June	1	16.8	8,661	$112,329	1.30	3,768	4,893	8,661	522	(4,371)
July	1	18.0	9,799	$118,974	1.21	5,874	3,925	9,799	4,803	879
August	1	19.2	10,412	$127,114	1.22	6,329	4,083	10,412	5,408	1,325
September	1	20.0	15,363	$133,002	0.87	7,531	7,832	15,363	2,218	(5,614)
October	1	20.1	15,869	$134,953	0.85	9,601	6,268	15,869	3,992	(2,276)
November	1	21.1	16,190	$140,351	0.87	10,841	5,349	16,190	8,163	2,814
December	1	24.7	16,342	$166,409	1.02	10,931	5,411	16,342	4,958	(453)
TOTAL		213.2	132,857.6	$1,437,663	1.08	79,714	53,143	132,858	53,148	4

	ENERGY BALANCING SERVICE – Revenue					
	Admin	Top-up	Spill Credit	Refund for Excess Spill	Total	Cents/kWh
January	$1,053	$182,414	-$378,156		-$194,689	(2.61)
February	$1,053	$229,794	-$217,372		$13,476	0.19
March	$1,053	$303,378	-$221,375		$83,056	1.00
April	$1,053	$334,169	-$246,186		$89,036	1.07
May	$1,053	$482,208	-$153,372		$329,889	3.71
June	$1,053	$487,284	-$27,519		$460,818	5.32
July	$1,053	$390,848	-$253,143		$138,759	1.42
August	$1,053	$406,629	-$285,022		$122,660	1.18
September	$1,053	$779,964	-$116,878		$664,140	4.32
October	$1,053	$624,245	-$210,382		$414,916	2.61
November	$1,053	$532,745	-$430,211		$103,587	0.64
December	$1,053	$538,841	-$261,262		$278,632	1.71
TOTAL	$12,636	$5,292,520	-$2,800,878	$0	$2,504,279	1.88

	STANDBY SERVICE – Coincident Firm Demand kW			STANDBY SERVICE – Revenue			
	Metered	Contributed Capacity	Net	Admin	Demand	Total	Cents/kWh
January	11,543	6,385	5,159	$1,053	$27,703	$28,756	0.39
February	12,534	6,385	6,150	$1,053	$33,023	$34,076	0.47
March	14,608	6,385	8,224	$1,053	$44,161	$45,214	0.54
April	14,778	6,385	8,393	$1,053	$45,073	$46,126	0.56
May	16,373	6,385	9,988	$1,053	$53,638	$54,691	0.62
June	16,358	6,385	9,973	$1,053	$53,555	$54,608	0.63
July	17,280	14,695	2,585	$1,053	$13,882	$14,935	0.15
August	18,648	14,695	3,952	$1,053	$21,224	$22,277	0.21
September	27,330	13,158	14,172	$1,053	$76,103	$77,156	0.50
October	28,956	14,695	14,261	$1,053	$76,582	$77,635	0.49
November	28,251	14,695	13,556	$1,053	$72,796	$73,849	0.46
December	30,565	14,695	15,869	$1,053	$85,219	$86,272	0.53
TOTAL	237,225	124,943	112,283	$12,636	$602,958	$615,594	0.46

	EMBEDDED COST RECOVERY under RTT – Energy-related		Demand-Related				Total Revenue	
	Displaced Energy (MWh)	Forgone Energy-related Revenue	Displaced Demand (MW)	Forgone Demand-related Revenue	Total Revenue	Cents/kWh	$ Amount	Cents/kWh
January	5,627	$186,197	6.4	$34,286	$220,483	3.0	$215,875	2.9
February	4,931	$163,167	6.4	$34,286	$197,453	2.7	$417,080	5.8
March	5,295	$175,200	6.4	$34,286	$209,486	2.5	$526,590	6.3
April	4,939	$163,432	6.4	$34,286	$197,717	2.4	$534,663	6.4
May	4,048	$133,952	6.4	$34,286	$168,238	1.9	$756,852	8.5
June	3,768	$124,673	6.4	$34,286	$158,959	1.8	$890,635	10.3
July	5,874	$194,371	14.7	$78,913	$273,284	2.8	$661,987	6.8
August	6,329	$209,427	14.7	$78,913	$288,340	2.8	$685,172	6.6
September	7,531	$249,201	13.2	$70,660	$319,861	2.1	$1,329,674	8.7
October	9,601	$317,697	14.7	$78,913	$396,610	2.5	$1,169,650	7.4
November	10,841	$358,729	14.7	$78,913	$437,642	2.7	$914,311	5.6
December	10,931	$361,707	14.7	$78,913	$440,620	2.7	$1,165,897	7.1
TOTAL	79,714	$2,637,752	124.9	$670,942	$3,308,694	2.5	$9,268,387	7.0

The remaining tabs in Appendix 24 have been provided in electronic format only.

Amendments to the

Wholesale Electricity Market Rules

for the Renewable to Retail Application are in these chapters:

Note: some chapter appendices to the Market Rules will need a name change only. Those documents are not provided here, but will be updated when the amendments to Market Rules are finalized.

The following chapters with content amendments are provided here:

- Chapter 1
- Chapter 1 Appendix 1A
- Chapter 2
- Chapter 2 Appendix 2C
- Chapter 3
- Chapter 4
- Chapter 5

Deleted: ¶

Deleted:

1, Introduction

1.0, Description

This chapter sets out the rules relating to the nature and scope of the Nova Scotia wholesale electricity market and Renewable to Retail electricity market, the nature, scope and applicability of the Market Rules, the relationship with other documents, and certain general provisions.

1.1, Nature and scope of the Nova Scotia wholesale electricity market and Renewable to Retail electricity market.

1.1.1, Bilateral markets

1.1.1.1, The Nova Scotia wholesale and Renewable to Retail electricity markets are markets in which eligible buyers and sellers may enter into bilateral transactions for the purchase and sale of electricity and related services. Eligible buyers and sellers (including eligible generators) may schedule their transactions over the Nova Scotia Transmission System in accordance with the Transmission Tariff and these Market Rules. Eligible generators may participate in the wholesale or Renewable to Retail markets and may sell certain Ancillary Services to the Nova Scotia Power System Operator (NSPSO) in accordance with these Market Rules.

Deleted:

Deleted: is a

Deleted: this

Deleted:

1.1.2, Object of the wholesale electricity market and Renewable to Retail electricity market

1.1.2.1, The design object of each of the wholesale and Renewable to Retail electricity markets is the promotion of economical supply through competitive opportunity amongst eligible participants within the context of a safe reliable Nova Scotia electricity system.

Deleted:

Deleted: s

1.1.3, Objects and responsibilities of the NSPSO

1.1.3.1, The objects of the NSPSO are:

a) the safe and reliable operation of the Bulk Electricity Supply System; and

Deleted: ¶

Deleted:

b) to support the object of the markets described in paragraph 1.1.2.1; to that end, the NSPSO will strive to perform its functions under the Market Rules in a manner that is:

i) non-discriminatory;

ii) transparent;

iii) robust; and

iv) efficient,

and in all cases subject to and in accordance with all Legislation and Regulations, the Transmission Tariff, the Standards of Conduct, and the Market Rules.

1.1.3.2, The responsibilities of the NSPSO are:

a) the specific responsibilities of the NSPSO stated in the Market Rules;

b) the responsibilities of NSPI to

i) file amendments to the Transmission Tariff,

ii) provide transmission service under the Transmission Tariff,

iii) provide Ancillary Services under the Transmission Tariff,

iv) operate the Transmission System in accordance with the Transmission Tariff, and

v) schedule transactions on the interconnections between Nova Scotia and New Brunswick;

Deleted: ¶

c) other responsibilities consistent with Legislation and Regulations, with the Transmission Tariff, with the Standards of Conduct and with the Market Rules, that may be assigned by NSPI.

1.1.4, Scope of eligibility for participation in the wholesale electricity market and Renewable to Retail electricity market

1.1.4.1, Eligibility for participation in the wholesale and Renewable to Retail electricity markets is defined in the Legislation and Regulations and in the Transmission Tariff.

a) The present definition of eligible persons for the wholesale electricity market is:

i) In accordance with the *Electricity Act*, S.N.S. 2004 c.25:

a Wholesale Customer

ii) In accordance with the Transmission Tariff:

"(1) Any electric utility (including the Transmission Provider and any power marketer), power marketing agency, or any person generating electricity for sale or resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico; and

(2) Any retail customer taking unbundled transmission service pursuant to a provincial or regulatory requirement that the Transmission Provider offer the transmission service is an Eligible Customer of the Tariff."

b) The present definition of eligible persons for the Renewable to Retail electricity market is:

i) In accordance with the *Electricity Act*, S.N.S. 2004, c. 25:

(1) a Licenced Retail Supplier

1.1.4.2, Notwithstanding the provisions of the Transmission Tariff quoted in sub-paragraph 1.1.4.1.a) (ii), there is presently no provincial or regulatory requirement that the Transmission Provider offer the transmission service to any retail customer. In recognition thereof, the Board in its order NSUARB-

Deleted: ¶

Deleted:

Deleted:

Deleted: s

Deleted:

Deleted: a

Deleted: ,

Deleted:

Deleted: ; "wholesale customers, [means] Nova Scotia Power Incorporated, the electric utilities of the towns of Antigonish, Berwick, Canso, Lunenburg and Mahone Bay and the Electric Light Commissioners for Riverport, in the County of Lunenburg."

Deleted: i

Deleted: i

Deleted: ii

Deleted: ii

Deleted: b

Deleted: ¶
Deleted:

NSPI-P-880 adopted the consensus proposal whereby "the OATT will be reviewed in the event the market is opened more broadly, and in such a review, the decisions made in this (May, 2005) proceeding will not be binding and shall not be treated as a precedent in any such subsequent review." In recognition of this provision, and of section 1.4, the Department of Energy retains certain rights with respect to amendment of the Market Rules associated with any change in the eligibility for participation, as also noted in paragraph 2.4.1.2.

Deleted: ¶

1.1.4.3, Eligibility for receipt of Bundled Service by a Municipal Utility from NSPI is not impacted by participation in the wholesale market. These Market Rules therefore make provision for a Municipal Utility that is also eligible for receipt of Bundled Service from NSPI to secure a portion of its supply though the wholesale market and a portion as Bundled Service.

Deleted:
Deleted: Market
Deleted: Participant

1.1.5, Nova Scotia Power Inc.

1.1.5.1, Nova Scotia Power Inc. (NSPI) has certain unique obligations and characteristics as particularly set out in the following sub-paragraphs.

a) Nova Scotia Power Inc. has obligations under Legislation and Regulations, and in particular under the *Public Utilities Act*, RSNS 1989, c.380 for the provision of Bundled Service to consumers in Nova Scotia who request such supply, all subject to regulation by the Nova Scotia Utility and Review Board (the "Board").

b) Nova Scotia Power Inc. has obligations under the Transmission Tariff approved by the Board for the provision of transmission services to eligible persons, generally the same as those eligible for market participation.

Deleted: ¶

c) The Nova Scotia Power System Operator (NSPSO) is a part of Nova Scotia Power Inc, Customer Operations division. The NSPSO's interaction with generation and commercial functions of Nova Scotia Power Inc is governed by Standards of Conduct attached to the Transmission Tariff. The requirements for Participation Agreements, cash settlements, etc. are not relevant to divisions of NSPI. All divisions of

Deleted: ¶

Deleted:

NSPI are however bound to these rules by virtue of NSPSO's execution of Participation Agreements with other Market Participants.

d) In view of the obligation of the NSPI Power Production division to serve the vast majority of provincial load and to provide Ancillary Services for supply to Transmission Customers under the Transmission Tariff, its generation scheduling and balancing arrangements are unique.

Deleted: ¶

These Market Rules recognise such unique provisions as they arise in each chapter or section.

Deleted: ¶

1.1.5.2, Nova Scotia Power Inc. is bound by these Market Rules:

a) as the Nova Scotia Power System Operator (NSPSO) in respect of all NSPSO rights and obligations under these Market Rules, including direction of operation of the Transmission System and in certain circumstances direction of the operation of Generating Facilities;

b) as the NSPSO acting on behalf of Customer Operations and Power Production divisions in respect of the actual control of the Transmission System and Distribution Systems, and of certain Generating Facilities;

c) as NSPI Customer Operations division in respect of responsibilities for the Transmission System;

d) as NSPI Customer Service division in respect of responsibilities for metering, metering data management, and settlement functions on behalf of the NSPSO;

e) as a Market Participant in respect of its Customer Operations division responsibilities for operation of Distribution Systems Connected to the Transmission System;

f) as a Market Participant in respect of its Power Production division responsibilities for operation of Generating Facilities and for energy supply under Bundled Service; and

Deleted: ¶
Deleted:

g) as a Market Participant in respect of its Power Production division activities relating to the import and export of electricity.

1.1.6, Existing Generating Facilities operating under NSPI Power Purchase Agreements

1.1.6.1, Unless otherwise determined by a NSPI Power Purchase Agreement or otherwise by agreement between the parties to such NSPI Power Purchase Agreement, paragraph 2.2.5.1 provides that NSPI PP or NSPI Customer Operations division will be the Market Participant for any Generating Facility in existence prior to the coming into effect of the Market Rules.

1.1.6.2, It is therefore NSPI PP or NSPI Customer Operations division which is responsible as Market Participant for compliance with these Market Rules in respect of such a Generating Facility.

1.1.6.3, These Market Rules are not intended to affect the rights and obligations of the parties to a NSPI Power Purchase Agreement or the associated Generator Interconnection Agreement that is in effect prior to the coming into effect of the Market Rules.

1.2, Nature and scope of Market Rules

1.2.1, Purpose of Market Rules

1.2.1.1, The purpose of the Market Rules is to define the rights and obligations of the NSPSO towards Market Participants, and of Market Participants towards the NSPSO, in respect of each of the wholesale and Renewable to Retail electricity markets described in section 1.1 and in the administration of the Transmission Tariff and the operation of the Bulk Electricity Supply System.

1.2.2, Subject matter of Market Rules

1.2.2.1, The Market Rules define rights and obligations between the NSPSO and Market Participants in respect of:

a) the markets themselves, their scope, objectives, and the Market Rules;

Deleted: itself
Deleted: its
Deleted: its

Deleted: ¶

Deleted:

b) administration of the markets, including market participation, Facilities, Market Rule amendment, compliance & monitoring, dispute resolution, data collection and analysis, and the confidentiality or publication of information;

c) planning and reliability functions in relation to the Bulk Electricity Supply System;

d) operational functions in relation to the Bulk Electricity Supply System, including scheduling of energy transactions and Ancillary Services; and

e) settlement functions.

1.3, Authority of Market Rules

1.3.1, Legislated and contractual authority

1.3.1.1, Legislation and Regulations prohibit a person from using the Transmission System directly as a Market Participant, or by interconnection of a Generating Facility with a Distribution System, except in accordance with these Market Rules.

1.3.1.2, Those persons wishing to use the Transmission System as Market Participants or to interconnect a Generating Facility to a Distribution System are thus required to execute a market Participation Agreement with the NSPSO. The Participation Agreement gives contractual force to the Market Rules with respect to the relationship between the NSPSO and the Market Participant.

1.3.2, Responsibilities to protect safety, assets and the environment

1.3.2.1, The Market Rules do not override any obligation or duty of the NSPSO or of any Market Participant for safety, for protection of assets from immediate harm, or for protection of the environment from immediate harm.

1.3.2.2, Any Market Participant becoming aware of any conflict between the Market Rules and any such obligation or duty shall notify the NSPSO of the conflict and

Deleted: ¶

Deleted:

of the circumstances, and shall collaborate with the NSPSO to mitigate impact and prevent recurrence.

1.4, Relationship with the Transmission Tariff and other regulated tariffs, rates and Board orders

1.4.1.1, It is the purpose of the Market Rules to define rights and obligations that are not the subject matter of the Transmission Tariff, of the Generator Interconnection Procedures, of the Standards of Conduct, of other tariffs or rates approved by the Board, or of any order of the Board, and to supplement the definition of Transmission Tariff rights and obligations where appropriate.

1.4.1.2, In the event of any conflict between a tariff (including schedules and attachments), the Generator Interconnection Procedures, the Standards of Conduct, a rate approved by the Board or an order of the Board, and these Market Rules, then the Board approved tariff, Generator Interconnection Procedures, Standards of Conduct, rate or Board order shall govern.

1.4.1.3, In the event that any Market Participant identifies any actual or potential conflict between a tariff (including schedules & attachments), the Generator Interconnection Procedures, the Standards of Conduct, a rate approved by the Board or an order of the Board and these Market Rules, it shall notify the NSPSO and seek clarification or appropriate correction.

1.4.1.4, These Market Rules are subject to and may be superseded by orders of the Board.

Deleted: rules

1.5, Subordinate and other documentation

1.5.1, General

1.5.1.1, The NSPSO may Publish subordinate documentation under these Market Rules, comprising standards, codes, and Market Procedures.

Deleted: ¶

Deleted:

1.5.1.2, The NSPSO and Market Participants shall comply with, and as applicable shall ensure that their Facilities comply with, all such standards and codes.

1.5.1.3, The NSPSO and Market Participants shall comply with Market Procedures in fulfilling their obligations under these Market Rules and if applicable under the Transmission Tariff.

1.5.2, Standards

1.5.2.1, Standards typically establish technical requirements for equipment, Facilities, systems, etc.

1.5.3, Codes

1.5.3.1, Codes may be used to define processes involving multiple Market Participants.

1.5.4, Market Procedures

1.5.4.1, Market Procedures typically define detailed processes to be used by the NSPSO and / or Market Participants in fulfilling obligations or exercising rights defined in the Market Rules.

1.5.4.2, Market Procedures exclude the internal procedures of the NSPSO and the internal procedures of Market Participants.

1.5.5, Conflicts

1.5.5.1, In the event that any Market Participant identifies any actual or potential conflict between any standard, code, or Market Procedure and a tariff (including schedules and attachments) or rate approved by the Board, or the NSPI Standards of Conduct, or these Market Rules, it shall notify the NSPSO and seek clarification or appropriate correction.

Deleted: ¶

Deleted:

1.6, General provisions

1.6.1, Computation of Time

1.6.1.1, In the computation of time under the Market Rules, unless a contrary intention appears, if there is a reference to a number of days between two events, they are counted by excluding the day on which the first event happens and including the day on which the second event happens.

1.6.1.2, In the computation of time under the Market Rules other than Chapter 4, unless a contrary intention appears, if the time for doing any act or thing expires on a day which is not a Business Day, the act or thing may be done on the next day that is a Business Day. In the computation of time under Chapter 4, unless a contrary intention appears, any act or thing required to be done on a day shall be done on such day whether or not a Business Day. The computation of time under a Market Procedure adopted in respect of the subject-matter of a chapter of the Market Rules shall be governed by the same rule as for the computation of time for that chapter.

1.6.1.3, In the Market Rules, unless the context otherwise requires:

Deleted: ¶

a) a reference to time is a reference to Atlantic time, which is the prevailing Atlantic standard or Atlantic daylight time in the Province of Nova Scotia;

b) a reference to time without the qualification "am", "a.m.", "pm" or "p.m." is a reference to time based on a 24-hour clock;

c) a reference to an hour ("hour 'x'") is a reference to the hour ending at x:00; and

d) a reference to hour "1" is a reference to the hour ending at 1:00 and all references to subsequent hours in a day are numbered accordingly.

1.6.2, Currency

1.6.2.1, All references in the Market Rules, a settlement statement or an invoice to a monetary amount are expressed in Canadian dollars.

Deleted: ¶

Deleted:

1.6.2.2, Any payment required to be made by or to the NSPSO or a Market Participant under any of the documents referred to in paragraph 1.6.2.1 shall be made in Canadian dollars.

1.6.3, Notice, Notification, Service and Filing

1.6.3.1, Subject to paragraph 1.6.3.3, and unless a contrary intention appears, notice is properly given, notification is properly made and service, filing, issuance and submission is properly effected under the Market Rules:

a) by courier or other form of personal delivery;

b) by registered mail addressed to the person at the address for service (if any) supplied by the person to the sender or, where the person is a Market Participant, to the address shown for that person in the list of Market Participants maintained by the NSPSO under paragraph 2.9.5.2 or, where the person is the NSPSO, to the registered office of the NSPSO;

c) by facsimile or electronic mail to a number or reference which corresponds with the address referred to in sub-paragraph 1.6.3.1(b); or

d) by web-based messaging to a number or reference which corresponds with the address assigned to the receiving person by the NSPSO under the applicable Market Procedure.

1.6.3.2, Subject to paragraph 1.6.3.3, and unless a contrary intention appears, notice, notification, service, filing, issuance or submission shall be treated as having been duly given, made or effected to a person by the sender:

a) where given, made or effected by facsimile in accordance with sub-paragraph 1.6.3.1(c) and a complete transmission report is issued from the sender's facsimile transmission equipment:

i) where notice, notification, service, filing or submission is of the type in relation to which the addressee is obliged to monitor the receipt by facsimile outside of, as well as during, business hours, on the

Deleted: ¶

Deleted:

day and at the time of transmission as indicated on the sender's facsimile transmission report; and

ii) in all other cases, on the day and at the time of transmission as indicated on the sender's facsimile transmission report, if a Business Day or, if the transmission is on a day which is not a Business Day or is after 5:00 pm (addressee's time), at 9:00 am on the following Business Day;

b) where given, made or effected by electronic mail in accordance with sub-paragraph 1.6.3.1(c):

i) where notice, notification, service, filing or submission is of a type in relation to which the addressee is obliged to monitor receipt by electronic mail outside of, as well as during, business hours, on the day and at the time when the notice or notification is recorded by the sender's electronic communication system as having been first received at the electronic mail destination; and

ii) in all other cases, on the day and at the time when the notice, notification or document or other material served, filed or submitted is recorded by the sender's electronic communications system as having been first received at the electronic mail destination, if a Business Day, or if that time is after 5:00 pm (addressee's time) or the day is not a Business Day, at 9:00 am on the following Business Day;

c) where given, made or effected by web-based messaging in accordance with sub-paragraph 1.6.3.1(d), on the day and at the time when the web-based message is sent; or

d) in any other case, when the person actually receives the notice, notification or document or other material served, filed or submitted.

1.6.3.3, Unless a contrary intention appears, instructions, directions and orders of the NSPSO may be given or issued to Market Participants:

Deleted: ¶

Deleted:

a) in accordance with paragraphs 1.6.3.1 and 1.6.3.2; or

b) by voice communication, in which case the instruction, direction or order shall be deemed validly given or issued at the time of communication.

1.6.4, Publication

1.6.4.1, In the Market Rules, unless a contrary intention appears, where any document or information is required by the Market Rules or by Legislation and Regulations to be Published by the NSPSO, Publication shall be effected by placing the document or information on that part of the NSPSO's web site that is accessible to the public. The document or information shall be deemed to be Published when the document or information has been so placed.

1.6.4.2, Where the Market Rules or Legislation and Regulations prescribe a mode of publication other than that described in paragraph 1.6.4.1 in respect of a specified document or information, the NSPSO shall, in addition to complying with paragraph 1.6.4.1 comply with the publication requirement applicable to such document or information as is so prescribed. In such a case, the document or information shall be deemed to be published on the date on which the prescribed publication requirement has been satisfied.

1.6.5, Liability and Indemnification

1.6.5.1, Except as otherwise provided in the Market Rules or in the Transmission Tariff, neither the NSPSO nor NSPI shall be liable for any claims, losses, costs, liabilities, obligations, actions, judgments, suits, expenses, disbursements or damages of a Market Participant or its directors, officers or employees whatsoever, howsoever arising and whether as claims in contract or in tort (including but not limited to negligence) or otherwise, arising out of any act or omission of the NSPSO in the exercise of any power or obligation under the Market Rules unless such claim, loss or damages result from wilful misconduct by or any negligent act or omission of the NSPSO.

Deleted: ¶

Deleted:

1.6.5.2, For the purposes of paragraph 1.6.5.1, an act or omission of the NSPSO effected in compliance with the Market Rules shall be deemed not to constitute wilful misconduct or a negligent act or omission.

1.6.5.3, Each Market Participant shall give prompt notice to the NSPSO of any claim with respect to which indemnification is being sought under paragraph 1.6.5.1.

1.6.5.4, Except as otherwise provided in the Market Rules other than in this sub-section 1.6.5, in no event shall the NSPSO be liable to indemnify and hold harmless a Market Participant or its directors, officers or employees from or in respect of:

a) any indirect or consequential loss or incidental or special damages, including punitive damages; or

b) any loss of profit, loss of contract, loss of opportunity or loss of goodwill;

and no Market Participant shall assert or attempt to assert any claim against the NSPSO or NSPI or its directors, officers, employees or affiliates in respect of any of the losses or damages referred to in sub-paragraphs 1.6.5.4 a) or 1.6.5.4 b).

Deleted: ¶

1.6.5.5, Each Market Participant shall have a duty to mitigate damages, losses, liabilities, expenses or costs relating to any claim for indemnification from the NSPSO that may be made under paragraph 1.6.5.1. Nothing in this paragraph 1.6.5.5 shall require the Market Participant to mitigate or alleviate the effects of any strike, lockout, restrictive work practice or other labour dispute.

1.6.5.6, Except as otherwise provided in the Market Rules, in Legislation and Regulations, or in the Transmission Tariff, a Market Participant shall not be liable for any claims, losses, costs, liabilities, obligations, actions, judgments, suits, expenses, disbursements or damages of the NSPSO or its directors, officers or employees whatsoever, howsoever arising and whether as claims in contract or in tort (including but not limited to negligence) or otherwise, arising out of any act or omission of the Market Participant in the exercise of any power or obligation under the Market Rules, unless such claim, loss or damages results from wilful misconduct by or any negligent act or omission of the Market Participant.

Deleted: ¶

Deleted:

1.6.5.7, For the purposes of paragraph 1.6.5.6, an act or omission of a Market Participant effected in compliance with the Market Rules shall be deemed not to constitute wilful misconduct or a negligent act or omission.

1.6.5.8, The NSPSO shall give prompt notice to the applicable Market Participant of any claim with respect to which indemnification is being sought under paragraph 1.6.5.6.

1.6.5.9, Except as otherwise provided in the Market Rules other than in this sub-section 1.6.5, in no event shall a Market Participant be liable to indemnify and hold harmless the NSPSO or its directors, officers or employees from or in respect of:

a) any indirect or consequential loss or incidental or special damages, including punitive damages; or

b) any loss or profit, loss of contract, loss of opportunity or loss of goodwill.

1.6.5.10 The NSPSO shall have a duty to mitigate damages, losses, liabilities, expenses or costs relating to any claim for indemnification from a Market Participant that may be made under paragraph 1.6.5.6. Nothing in this paragraph 1.6.5.10 shall require the NSPSO to mitigate or alleviate the effects of any strike, lockout, restrictive work practice or other labour dispute.

1.6.5.11 Nothing in this sub-section 1.6.5 shall be read as limiting the right of the NSPSO to impose a financial penalty or other sanction, including the imposition of conditions on Market Participant, Suspension or Termination of that Market Participant, or Disconnection of its Facilities in accordance with the provisions of the Market Rules.

1.6.6, Force Majeure

1.6.6.1, The Force Majeure provisions of the Transmission Tariff, including in particular section 10.1 thereof, are applicable to the Market Rules.

Deleted: ¶

Deleted:

1.6.7, Contractual Liability

1.6.7.1 The liability and indemnification provisions of sub-section 1.6.5 and, where applicable, of any other section of the Market Rules other than this paragraph 1.6.7.1, and the Force Majeure provisions of sub-section 1.6.6 shall apply to any agreement or contract referred to in the Market Rules to which the NSPSO and a Market Participant are parties or to the terms of which the NSPSO and a Market Participant are bound and to all acts or omissions of the NSPSO or the Market Participant in the exercise or performance or the intended exercise or performance of any power or obligation under such agreement or contract. In the event of an inconsistency between such liability, indemnification and Force Majeure provisions and the liability, indemnification and Force Majeure provisions of such agreement or contract, the liability and indemnification provisions of sub-section 1.6.5 and, where applicable, of any other section of the Market Rules, and the Force Majeure provisions of sub-section 1.6.6 shall prevail to the extent of the inconsistency.

1.7, Definitions and interpretation

1.7.1, Defined terms and acronyms

1.7.1.1, Defined terms used in these Market Rules are capitalized.

1.7.1.2, Terms defined for the purposes of these Market Rules are set out in Appendix 1A.

1.7.1.3, Unless otherwise defined in these Market Rules, or unless the context otherwise requires, terms defined in the Transmission Tariff have the meaning in these Market Rules that is ascribed to them in the Transmission Tariff.

1.7.1.4, Unless otherwise defined in these Market Rules or the Transmission Tariff, or unless the context otherwise requires, terms defined in the Legislation and Regulations have the meaning in these Market Rules that is ascribed to them in the Legislation and Regulations.

1.7.1.5, Acronyms used in these Market Rules are defined in Appendix 1A.

Deleted: ¶

Deleted:

1.7.2, General rules of interpretation

1.7.2.1, General rules of interpretation are set out in Appendix 1B.

1.7.3, Questions of interpretation

1.7.3.1, Any person having a question of interpretation of the Market Rules should address such question to the NSPSO.

Deleted: acronyms

Deleted: 30th September, 2006¶

Appendix 1A

Definitions and acronyms

Ref	Acronym or term	Chapter	Definition or reference
1A.000	Act	General	The Electricity Act, S.N.S. 2004, c. 25, as amended from time to time.
1A.001	Adequacy	3 & 4	The ability of a Zone, a Transmission System or the Bulk Electricity Supply System to supply aggregate electrical demand and energy requirements to some recognized degree of certainty at all times, taking into account scheduled and reasonably unscheduled Outages of facilities, equipment or components.
1A.002	Ancillary Service	General	In accordance with the Transmission Tariff section 1.0 "Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice."
1A.003	Board	General	The Nova Scotia Utility and Review Board (as also defined in Transmission Tariff section 1.0).
1A.004	Bulk Electricity Supply System	General	The Transmission System and all Generating Facilities required in accordance with these market Rules to be registered with the NSPSO, including all related communication, protection and control systems, etc.

Deleted: *acronyms*

Deleted: 30th September, 2006¶

1A.005	Bundled Service	General	In accordance with the Transmission Tariff section 1.0. "Electrical service taken from NSPI under Rates and Regulations approved by the Board. This takes the form of having generation, transmission, distribution, ancillary services and all other items associated with the provision of such service blended or bundled within the rate." For certainty, Bundled Service does not include services taken from NSPI under the Distribution Tariff, the Energy Balancing Service Tariff, the Standby Service Tariff or the Renewable to Retail Market Transition Tariff. As used in the Market Rules, the term refers to the service provided at a Transmission System Point of Delivery, exclusive of use of a Distribution System. *Related definition: Partially Unbundled Service*
1A.006	Business Day	General	In accordance with the Transmission Tariff section 1.0 "A Business Day is Monday to Friday, inclusive, excluding holidays. The regular business hours on a Business Day are from 08:30 to 16:30 Atlantic Time."

Deleted: *acronyms*

Deleted: *30th September, 2006*

1A.007	Confidential Information	General	Information that is (a) expressly required by the Market Rules or a Market Procedure to be kept confidential; (b) identified in writing as confidential by the disclosing person at the time of disclosure; or (c) derived from information referred to in (a) and (b), but does not include information that is required by the Market Rules to be Published by the NSPSO in its original or a modified form or otherwise made available to others Further, the following will not constitute Confidential Information for purposes of these Market Rules: (i) information which is or becomes generally available to the public other than as a result of a disclosure by the NSPSO or its authorized representatives; (ii) information which was already known to NSPSO on a non-confidential basis prior to being furnished to NSPSO by a Market Participant; (iii) information which becomes available to NSPSO on a non-confidential basis from a source other than a Market Participant or a representative of a Market Participant if such source was not subject to any prohibition against transmitting the information to NSPSO and was not bound by a confidentiality agreement with the Market Participant; or (iv) information which was independently developed by the NSPSO or its representatives without reference to, or consideration of, the Confidential Information.
1A.008	Connect	General	Complete and commission the physical works needed to allow synchronization of a Generating Facility, Load Facility or Distribution System to the Transmission System. *Related definitions: Disconnect, Synchronize*
1A.009	Connected	General	Having the physical works needed to allow synchronization of a Generating Facility, Load Facility or Distribution System to the Transmission System.
1A.010	Connection Applicant	3	A person who has executed a System Impact Study agreement with NSPI in accordance with the Generation Interconnection Procedure.
1A.011	Control Action	4	An action taken by the NSPSO for the preservation of Reliability, which is beyond the normal operating regime of the wholesale and Renewable to Retail electricity markets.

Deleted: *acronyms*

Deleted: 30th September, 2006¶

1A.012	Day Ahead	4	In respect of a Dispatch Day, the last Business Day preceding the Dispatch Day.
1A.013	De-synchronize	4	Temporarily break the connection, typically by opening a breaker, between a Facility and the Transmission System. *Related definitions; Synchronize; Disconnect*.
1A.014	Disconnect	General	Remove, on a permanent or enduring basis, the ability of a Facility to be synchronized to the Transmission System. *Related definitions: Connect; De-synchronize.*
1A.015	Dispatch Day	4	Any day on which the NSPSO schedules and dispatches Facilities including a Saturday, Sunday or holiday.
1A.016	Dispatchable Generating Facility	2, 4	As defined in paragraph 2.2.4.1.
1A.016.1	Distribution Generator Interconnection Procedures	2	The NSPI standard generator interconnection procedures applicable to Generating Facilities ≥ 101kW, connected to Distribution Systems.
1A.018	Distribution System	1, 2	A system for the conveyance of electricity at voltages less than 69 kV, including any transformer station for the transformation of electricity from voltages of 69 kV and above to voltages below 69 kV, and including all communications, protection and control equipment that interacts with the Transmission System. Note that this is broader than the definition in the Generator Interconnection Agreement as it includes Distribution Systems owned by persons other than NSPI.
1A.019	DSM or Demand Side Management	3	DSM refers to activities or programs undertaken by a utility or its customers to influence the amount and timing of electricity usage. Included in DSM are the planning, implementation, and monitoring of activities that are designed to influence electricity use in ways that produce desired changes in load shape, such as direct load control, interruptible load, energy efficiency and conservation.

Deleted: acronyms

Deleted: 30th September, 2006¶

1A.020	Emergency Planning Participant	3	A Market Participant identified by the NSPSO as an Emergency Planning Participant in accordance with sub-section 3.6.1.
1A.021	Export Generating Facility	2, 3 & 4	As defined in paragraphs 2.2.4.13 to 2.2.4.19.
1A.022	Facility	General	A Generating Facility, Load Facility or Distribution System.
1A.023	Facility Reactive Power Capability	4, 5	As defined in paragraph 5.5.1.2.
1A.024	Facility Reactive Power Capability Share	5	As defined in paragraph 5.5.1.4.
1A.025	Force Majeure	1	Force Majeure is defined for the purpose of these Market Rules by section 10.1 of the Transmission Tariff "An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing by any party."
1A.026	Forced Outage	3, 4	The removal from service of equipment for emergency reasons or a condition in which the facility equipment is unavailable, in whole or in part, due to unanticipated failure, and includes a forced de-rating. For greater certainty, the urgent removal from service or de-rating of equipment in order to prevent an actual failure that could jeopardize safety, the environment, or the equipment itself may, if it could not reasonably have been anticipated, be considered a Forced Outage.
1A.027	General Reliability Standards	3	As defined in paragraph 3.2.1.1.

Deleted: *acronyms*

Deleted: 30th September, 2006¶

1A.028	Generating Facility	General	One or more generators located at a single site together with all associated prime movers, station service equipment, communications protection and control equipment, and including any transformer station for the transformation of electricity to the voltage at which it is delivered to the transmission system or distribution system to which it is connected. Note that this is broader than the definition in the Generator Interconnection Agreement as it includes the Interconnection Customer's Interconnection Facilities, and it includes Generating facilities connected to a Distribution System.
1A.029	Generation Market Participant	General	A Market Participant for one or more Generating Facilities.
1A.030	Generator Interconnection Agreement	2	The standard generator interconnection and operating agreement which forms Appendix 6 of the Generator Interconnection Procedures.
1A.031	Generator Interconnection Procedures	2, 3	The NSPI standard generator interconnection procedures approved by the Board. This is not part of the Transmission Tariff, but is referenced in attachment D to the Transmission Tariff.
1A.032	Intermittent Generating Facility	2, 4	As defined in paragraphs 2.2.4.2 to 2.2.4.4.
1A.033	Legislation and Regulations	General	i) The law of Nova Scotia including the *Electricity Act*, SNS 2004, c.25 and the *Public Utilities Act*, RSNS 1989, c.380. ii) Regulations under the above acts, and iii) The laws of Canada as applicable all as amended from time to time.

Deleted: *acronyms*

Deleted: 30th September, 2006¶

1A.033.1	Licenced Retail Supplier	General	A Retail Supplier who: (a) holds a valid Retail Supplier Licence; and (b) has a valid LRS Participation Agreement executed with NSPI. For certainty, a Wholesale Customer is not a Licenced Retail Supplier.
1A.033.2	LRS Participation Agreement	General	The agreement (and any amendments or supplements thereto) between a LRS and NSPI with respect to the sale of renewable low-impact electricity by the LRS in the form approved by the Board.
1A.033.3	Licenced Retail Supplier Market Participant		A Licenced Retail Supplier who has executed a market Participation Agreement (as defined in the Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules Appendix 1A) with the NSPSO in accordance with the requirements of the Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules.
1A.034	Load Displacement Generating Facility	2, 4	As defined in paragraphs 2.2.4.9 to 2.2.4.12.
1A.035	Load Facility	General	A facility to which electricity is supplied from the Transmission System, including any transformer station for the transformation of electricity from 69 kV or higher voltage to below 69 kV, and including communications protection and control equipment that interacts with the Transmission System.
1A.036	Load Market Participant	General	A Market Participant for one or more Load Facilities or Distribution Systems.
1A.037	Market Manual	2	The Market Rules, codes, standards and Market Procedures that govern the wholesale and Renewable to Retail electricity market in Nova Scotia.

Deleted: 1

Deleted: *acronyms*

Deleted: 30th September, 2006¶

Deleted: ¶

Deleted: 1

1A.038	Market Participant	General	A person who has executed a Participation Agreement with the NSPSO, and NSPI itself as specified in sub-paragraphs 1.1.5.2 (e), (f), and (g). For certainty, a person may be a Market Participant with respect to the wholesale electricity market or the Renewable to Retail electricity market.
1A.039	Market Participant Reactive Power Capability Share	5	As defined in paragraph 5.5.1.11.
1A.040	Market Procedure	General	A Published document entitled as such and that contains procedures, processes and forms to be used by the NSPSO, Market Participants and others in fulfillment of their respective obligations under the Market Rules.
1A.041	Market Rules	General	The Wholesale and Renewable to Retail Market Rules made by the Nova Scotia Department of Energy as amended from time to time in accordance with section 2.4.
1A.042	Minor Generating Facility	2, 4	As defined in paragraphs 2.2.4.5 to 2.2.4.8.
1A.042.1	Municipal Utility	1	This term has the same meaning as under the Act.
1A.043	MVAR	5	Mega volt-amps reactive.
1A.044	NBSO	3, 4	New Brunswick System Operator.
1A.045	NERC	3	North American Electricity Reliability Council.
1A.046	Network Integration Transmission Service	4	In accordance with the Transmission Tariff, this is defined as the transmission service provided under part III of the Transmission Tariff.
1A.047	Network Operating Agreement	2	In accordance with the Transmission Tariff section 1.0 "An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Open Access Transmission Tariff."
1A.048	NPCC	3	North East Power Coordinating Council.

Deleted: *acronyms*

Deleted: *30th September, 2006¶*

1A.049	NSPI	General	Nova Scotia Power Inc.
1A.050	NSPI Power Purchase Agreement	1	An agreement between NSPI and an independent power producer for the purchase by NSPI of all the capacity and energy of one or more Generating Facilities owned or to be developed by the independent power producer, such that title to the purchased capacity and energy is transferred to NSPI at the Generating Facility.
1A.051	NSPI PP	General	The Power Production division of NSPI.
1A.052	NSPI Rates and Regulations	5	Documents titled as such, published by NSPI in accordance with one or more orders of the Board.
1A.053	NSPSO	General	Nova Scotia Power System Operator, a part of the Customer Operations division of NSPI.
1A.054	OASIS	4	Open Access Same-time Information System, being a web-accessible system operated by or for NSPI.
1A.055	Outage	3, 4	The removal of equipment from service, unavailability for Synchronization of equipment or temporary de-rating, restriction of use or reduction in performance of equipment below its characteristics as reflected in the applicable registration data, for any reason, and includes a Planned Outage and a Forced Outage.
1A.056	Outage Plan	3	A plan by NSPI or another Market Participant for one or more Outages of transmission elements or Generating Facilities.
1A.057	Partially Unbundled Service	General	Service provided by NSPI to wholesale customers for the supply of a portion of the electricity supplied from the Transmission System, in accordance with rates and regulations approved by the Board. *Related definitions: Bundled Service; Unbundled Service*
1A.058	Participant Emergency Plan	3	The plan required to be prepared by an Emergency Planning Participant in accordance with sub-section 3.6.2.

Deleted:

Deleted: *acronyms*

Deleted: 30th September, 2006¶

1A.059	Participation Agreement	1,2	The agreement in the form set forth in Appendix 2A executed between the NSPSO and each Market Participant other than NSPI following accreditation in accordance with sub-section 2.1.3.
1A.060	Planned Outage	3	An Outage that is planned and intentional.
1A.061	Point of Delivery	5	In accordance with the Transmission Tariff section 1.0 "Point on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service". As used in the Market Rules the term also includes Network Integration Transmission Service under part III of the Transmission Tariff.
1A.062	Point of Receipt	5	In accordance with the Transmission Tariff section 1.0 "Point of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service." As used in the Market Rules the term also includes Network Integration Transmission Service under part III of the Transmission Tariff.
1A.063	Point to Point Transmission Service	4	In accordance with the Transmission Tariff, this is defined as the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Points(s) of Delivery under part II of the Transmission Tariff.

Deleted: *acronyms*

Deleted: *30th September, 2006*

1A.064	Prudential Support	2	One or more of a guarantee, Letter of Credit (as defined below) or other credit support from a person, each of which is in an amount, in a form and/or issued by a party which is set forth in the relevant Market Procedure or is otherwise acceptable to the NSPSO, securing the obligations owed or to be owed to the NSPSO by a Market Participant. "Letter(s) of Credit" shall mean one or more irrevocable, transferable standby letters of credit issued by a Schedule I Canadian Chartered Bank or a Canadian branch of a U.S commercial bank, with such bank having a Credit Rating (defined below) of at least A- from Standard & Poor's Ratings Group (a division of McGraw-Hill, Inc.) or its successor ("S&P") or A3 from Moody's Investor Services, Inc., or its successor ("Moody's"), in a form and for an amount acceptable to the NSPSO in its reasonable discretion. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit and not the NSPSO. "Credit Rating" means, with respect to an entity, the rating then assigned to such entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements) or, if such entity does not have a rating for its senior unsecured long-term debt, the rating then assigned to such entity as an issuer rating, in each case, by S&P, Moody's and/or any other ratings agency designated by the NSPSO from time to time.
1A.065	Publish	General	Make available to any person, as a minimum by posting on a readily accessible public access NSPI website.
1A.066	Re-dispatch	4, 5	An instruction by the NSPSO that a Dispatchable Generating Facility be operated at a level of output different than that scheduled by the Market Participant.
1A.067	Reliability	General	The degree of performance of a Zone, a Transmission System, the Bulk Electricity Supply System that results in electricity being delivered within accepted standards in an Adequate and secure manner and in the amount desired.
1A.068	Reliability Coordinator	3, 4	The NBSO in its role as electricity system reliability coordinator for the Maritime region.

Deleted: *acronyms*

Deleted: 30th September, 2006¶

1A.068.1	renewable low-impact electricity	General	This term has the same meaning as in the Renewable Electricity Regulations (Nova Scotia).
1A.068.2	Renewable to Retail	General	Describes the market in which renewable low-impact electricity generated in Nova Scotia may be sold by Licenced Retail Suppliers to Retail Customers in Nova Scotia in accordance with the Act.
1A.068.3	Retail Customer	General	This term has the same meaning as under the Act. For certainty, a customer of a Municipal Utility is not a Retail Customer.
1A.068.4	Retail Supplier	General	This term has the same meaning as under the Act.
1A.068.5	Retail Supplier Licence	General	A Retail Supplier licence issued by the Board in accordance with the Act and Regulations made thereunder which authorizes a person to sell renewable low-impact electricity generated within the Province.
1A.069	Special Locational Loss Factor	2, 5	A reasonable estimate by the NSPSO of the “excess” of (a) the marginal energy loss in transmission of the output from incremental new generation to the general load pool, over (b) the system average energy loss in transmission as reflected in the Transmission Tariff in respect of Network Integration Service, expressed as a percentage. In the even that such marginal losses from incremental generation are less than the system average, then the “excess” will be a negative percentage value.
1A.070	Standards of Conduct	General	The NSPI Standards of Conduct approved by the Board and forming Attachment E to the Transmission Tariff.
1A.070.1	Standard Small Generator Interconnection and Operating Agreement	2, 5	An agreement between NSPI and the owner of a Generating Facility defining the terms and technical requirements governing the connection of the Generating Facility to NSPI’s Distribution System.
1A.071	Suspend	1,2	Temporarily suspend all or some of a Market Participants rights under the Market Rules.

Deleted:

Deleted: *acronyms*

Deleted: *30th September, 2006*

1A.072	Synchronize	2, 4	Make the connection, typically by closing the relevant breaker, between a Facility and the Transmission System to permit the flow of energy or other services. *Related definitions: Connect; De-synchronize.*
1A.073	System Impact Study	5 (para 5.5.1.2)	An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.
1A.074	System Reactive Power Capability	5	As defined in paragraph 5.5.1.3.
1A.075	Temporary Waiver	2	A temporary waiver of an obligation under the Market Rules granted by the NSPSO in accordance with section 2.5.
1A.076	Terminate	1, 2	Permanently terminate the rights of a Market Participant under a Participation Agreement.
1A.077	Transmission Customer	1, 2	A Market Participant who is a Transmission Customer as defined in section 1.0 of the Transmission Tariff.
1A.078	Transmission Loading Relief	4	A process described in NERC standard IRO-006-1.
1A.079	Transmission Provider		The NSPI Customer Operations division, including the NSPSO.
1A.080	Transmission Service Information Network	2	The Transmission Service Information Network operated by the North American Electricity Reliability Council.
1A.081	Transmission System	General	In accordance with the Transmission Tariff section 1.0 "The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff".
1A.082	Transmission Tariff	General	The NSPI Open Access Transmission Tariff approved by the Board.

Deleted: *acronyms*

Deleted: 30th September, 2006

1A.083	Unbundled Service	General	Service to a Transmission Customer for Network Integration Service or Point to Point Service, separately from any provision of energy by NSPI PP. *Related definitions: Bundled Service; Partially Unbundled Service*
1A.084	VAR	4	Volt-amps reactive.
1A.085	Wholesale and Renewable to Retail Market Advisory Committee	2	The committee established in accordance with section 2.3.
1A.086	Zone	2, 3	A part of the Bulk Electricity Supply System to which the NSPSO gives separate consideration in view of the fact that the level of Reliability may differ from the general level of Reliability of the system including as a result of transmission constraints.
1A.087	Wholesale Customer	General	This term has the same meaning as under the Act.

Deleted: 30th September, 2006

2, Market Administration

2.0, Description

This chapter sets out the rules relating to participation in the markets, including the rules setting out requirements for becoming a Market Participant. This chapter also sets out the rules governing the administration of the markets. These rules apply to the NSPSO and to Market Participants.

2.1, Market Participation

2.1.1, Qualifications to be a Market Participant

2.1.1.1, Any person eligible as described in paragraph 1.1.4.1 to be a Market Participant in either the wholesale or Renewable to Retail markets may apply to the NSPSO to become a Market Participant.

2.1.1.2, The NSPSO shall accredit such a person as a Market Participant in the applicable market if:

a) the person agrees to be bound by the Market Rules by executing a Participation Agreement in the form set out in Appendix 2A;

b) the NSPSO is reasonably satisfied that the person will satisfy credit support and technical requirements;

c) the person provides its valid GST or HST registration number or evidence of exemption;

d) the person is not ineligible by reason of forced Termination; and

e) if the person is to be a Transmission Customer, the person provides evidence of Open Access Technology International accreditation.

Deleted: Transmission Service Information Network

2.1.1.3, A person who expects to become eligible to be a Market Participant in either the wholesale or Renewable to Retail markets may apply to the NSPSO in advance of such eligibility, and the NSPSO shall accredit such a person who fulfils the requirements of paragraph 2.1.1.2 conditional on actual eligibility.

Deleted: 30th September, 2006

2.1.2, Classes of Market Participants

2.1.2.1, An eligible person may be a Market Participant in one or more of the following classes:

a) Generation Market Participant: A Generation Market Participant is a Market Participant in respect of

i) a Generating Facility connected to the Transmission System; or

ii) a Generating Facility connected to a Distribution System and registered with the NSPSO.

b) Load Market Participant: A Load Market Participant is a Market Participant in respect of

i) a Load Facility connected to the Transmission System; or

ii) a Distribution System connected to the Transmission System.

c) Licenced Retail Supplier Market Participant: A Licenced Retail Supplier Market Participant is a Market Participant in respect of the aggregate of the Retail Customer load subscribed to the Licenced Retail Supplier.

d) Transmission Customer: A Transmission Customer is a Market Participant eligible to schedule transactions on the Transmission System. Generation Market Participants, Load Market Participants and Licenced Retail Supplier Market Participants must also be Transmission Customers if they are to schedule transactions on the Transmission System.

Deleted: c

Deleted:

Deleted: and

2.1.3, Application to be a Market Participant

2.1.3.1, The NSPSO shall issue in a Market Procedure the forms and procedures to be used by any person to apply for accreditation as a Market Participant.

2.1.3.2, The NSPSO shall promptly review for completeness any application received, and shall advise the applicant of any omissions and any additional information required to complete the application.

2.1.3.3, The NSPSO shall review any complete application received, and shall within15 Business Days of receipt of the complete application either:

Deleted: 30th September, 2006

a) advise the applicant that it is accredited subject to any outstanding execution of agreements or fulfilment of Prudential Support or other specific requirements,

b) advise the applicant that it is accredited conditional on fulfilment of eligibility requirements and subject to any outstanding execution of agreements or fulfilment of Prudential Support or other specific requirements, or

c) advise the applicant of rejection of its application and the grounds for such rejection.

2.1.3.4, Any applicant whose application is rejected may exercise any rights of appeal to the Board that are provided in Legislation and Regulations.

2.1.3.5, In the event that any such appeal has been successful, the NSPSO shall review or reconsider the relevant application in accordance with the order of the Board.

2.1.4, Provision of credit support

2.1.4.1, If, at the time of application for accreditation or at any time thereafter, the NSPSO expects that a Market Participant will owe money to the NSPSO in respect of settlement in addition to any amounts contemplated in the Transmission Tariff, the NSPSO may require evidence of credit rating or may require Prudential Support commensurate with the expected maximum net settlement amount.

2.1.4.2, If the NSPSO identifies the actual or probable need for Prudential Support, it shall determine the amount of such Prudential Support in accordance with a Market Procedure, which shall also set out the terms under which such Prudential Support is to be provided.

Deleted: y

2.1.4.3, If the NSPSO has required evidence of a certain credit rating or has determined in accordance with its Market Procedure a requirement for Prudential Support, and if the Market Participant has not provided the required evidence of credit rating or the required Prudential Support, the NSPSO may impose conditions

Deleted: *30th September, 2006*

on the Market Participant's activity to limit the amount of the debt to the NSPSO that the Market Participant may accrue.

2.1.5, Continuing to be a Market Participant, and recognition of changes

2.1.5.1, Every Market Participant shall promptly advise the NSPSO of any change in circumstances that might affect its continuing qualification to be a Market Participant, and of any change to the information provided in its application for accreditation as a Market Participant.

2.1.5.2, A Market Participant in one or more classes may apply to become a Market Participant in one or more other classes, and the NSPSO shall grant such application subject to fulfilment by the applicant of any changed accreditation requirements.

2.1.5.3, The NSPSO may impose conditions on a Market Participant's activity in accordance with sub-section 2.6.3 or if the Market Participant ceases to meet the qualifications to be a Market Participant.

2.1.6, Ceasing to be a Market Participant

2.1.6.1, Any Market Participant that is not either a Generation Market Participant or a Load Market Participant, may at any time give notice to the NSPSO that it wishes to cease to be a Market Participant.

2.1.6.2, Any Generation Market Participant or Load Market Participant must Disconnect and de-register its registered Facilities in accordance with paragraphs 2.2.8.1 to 2.2.8.3, or must assign responsibilities for all its registered Facilities to another Market Participant in accordance with paragraphs 2.2.2.3 to 2.2.2.4, before it can cease to be a Market Participant.

2.1.6.3, The NSPSO may Terminate the market participation rights of any person in accordance with sub-section 2.6.3 below or if the Market Participant ceases to meet the qualifications to be a Market Participant.

2.1.6.4, Any person ceasing to be Market Participant, either on a voluntary basis or as a result of Termination, is not excused from any prior or outstanding obligations,

Deleted: 30th September, 2006

and shall continue to be bound by the Market Rules in respect of such obligations.

2.1.7, Nova Scotia Power Inc. (NSPI)

2.1.7.1, NSPI Power Production division ("NSPI PP") is deemed for the purposes of these Market Rules to be a Generation Market Participant, and a Transmission Customer (in respect of any exports it undertakes, and in respect of the use of the Transmission System for Bundled Service supply, which may include imports).

2.1.7.2, NSPI Customer Operations division is deemed for the purposes of these Market Rules to be a Load Market Participant (in respect of all Facilities at Points of Delivery for Bundled Service consumers).

2.1.7.3, NSPI Customer Service division performs certain functions on behalf of the NSPSO, but is not deemed to be a Market Participant.

2.2, Connected Facilities

2.2.1, Facility registration

Facilities requiring to be registered

2.2.1.1, All Generating Facilities and Load Facilities connected to the Transmission System, and all Distribution Systems, must be registered with the NSPSO prior to their first Synchronization in order to provide the NSPSO with all relevant information.

2.2.1.2, Any Generating Facility that is connected to either a Load Facility or Distribution System and that is to be subject to NSPSO scheduling or settlement, including in respect of Ancillary Service provision, must be registered with the NSPSO.

2.2.1.3, Any Generating Facility over 5 MW total capacity that is connected to a Load Facility or Distribution System must be registered with the NSPSO.

Deleted: 30th September, 2006

Requirements for registration

2.2.1.4, In order to be registered, a Facility must be, as applicable:

a) owned and controlled by NSPI;

b) receiving only Bundled Service from NSPI;

c) for a Generating Facility connected to the Transmission System - the subject of a Generator Interconnection Agreement in accordance with the Transmission Tariff;

d) for a Generating Facility connected to a Load Facility – the subject of a Network Operating Agreement with NSPI;

Deleted: n

e) for a Generating Facility connected to a Distribution System - the subject of a Distribution Interconnection Agreement with the distributor, and if the Distribution System is owned other than by NSPI, recognised in the Network Operating Agreement of the distributor; or

f) for a Load Facility or Distribution System receiving service other than Bundled Service from NSPI - the subject of a Network Operating Agreement in accordance with the Transmission Tariff.

Separation and aggregation

Deleted: ¶

2.2.1.5, The NSPSO may designate that individual units in a large generating station be registered as separate Generating Facilities.

2.2.1.6, The NSPSO may permit several Generating Facilities with the same or closely related connections to the Transmission System to be aggregated for the purposes of schedule submission, dispatch and settlement.

2.2.1.7, The NSPSO may permit the aggregation of closely located Load Facilities and Generating Facilities of the same Market Participant to the extent that this represents past practice before the coming into effect of these Market Rules.

2.2.1.8 The NSPSO may permit the aggregation of the Retail Customer load subscribed to an individual Licenced Retail Supplier.

Deleted:

Deleted: c

Deleted: 30th September, 2006

Market Procedure

2.2.1.9, The NSPSO shall publish in a Market Procedure any registration requirements that are additional to those set out in the Generator Interconnection Agreement, Network Operating Agreements or other operating agreements in respect of Generating Facilities embedded in Load Facilities.

Deleted: 8

2.2.2, Market Participant for a Facility

2.2.2.1, For every Generating Facility, Load Facility or Distribution System connected to the Transmission System or registered with the NSPSO, there must be one and only one Generation Market Participant or Load Market Participant.

2.2.2.2, The Market Participant for a Facility may be the owner or operator of the Facility or another person, and must demonstrate to the NSPSO that it has adequate control over relevant aspects of the Facility operation to be responsible to the NSPSO for its operation.

Assignment of full or partial Market Participant responsibility

2.2.2.3, Subject to the above requirements, subject to the agreement of both Market Participants, and subject to notice to the NSPSO, a Market Participant may assign responsibility for a Facility to another Market Participant.

2.2.2.4, The Load Market Participant for a Facility may subject to the agreement of the assignee and notice to the NSPSO assign complete or partial Transmission Customer responsibilities in respect of the Facility to a Transmission Customer Market Participant. Absent any such assignment, the Load Market Participant is also the Transmission Customer Market Participant for that Facility.

2.2.2.5, In the event of assignment of partial Transmission Customer responsibilities, the assigning Market Participant shall provide to the NSPSO reasonable evidence that the parties have agreed to the terms of such partial assignment of responsibilities, including agreement with respect to allocation of responsibility for settlement in respect of metering and in respect of settlement for metered demand, energy and reactive power quantities.

Deleted: 30th September, 2006

Appointment of an agent

2.2.2.6, Any Market Participant may appoint any person to act as its agent. Any Market Participant appointing an agent remains responsible for all actions of that agent.

Deleted: ¶
¶

2.2.3, Classes of Facilities

2.2.3.1, A Facility may be either:

a) a Generating Facility, which shall include any Facility that has net injection to the Transmission System in any hour of the year, as well as any Facility with a total generating capacity greater than 5 MW even if embedded in a Load Facility or in a Distribution System;

b) a Load Facility, which shall include any Facility that is not primarily for the purpose of generating electricity;

c) both of the above; or

d) a Distribution System, including a municipally owned Distribution System that is only indirectly connected to the Transmission System.

2.2.4, Classes of Generating Facilities

Dispatchable Generating Facilities

2.2.4.1, Every Generating Facility is a Dispatchable Generating Facility unless it has been classified by the NSPSO either as an Intermittent Generating Facility, as a Minor Generating Facility, as a Load Displacement Generating Facility or as a non-Dispatchable Export Generating Facility.

Intermittent Generating Facilities

2.2.4.2, The Market Participant for a Generating Facility may at the time of its application for initial registration, and subject to the conditions set out below, apply for its registration as an Intermittent Generating Facility.

2.2.4.3, The NSPSO shall accede to such request and register the Generating Facility as an Intermittent Generating Facility if it is satisfied that the output of the

Deleted: *30th September, 2006*

Generating Facility is determined by uncontrollable factors such as wind, uncontrolled river flows, etc.

2.2.4.4, For the sake of clarity, an Intermittent Generating Facility is a Generating Facility and subject to all applicable provisions of these Market rules except where explicitly excluded.

Minor Generating Facilities

2.2.4.5, The Market Participant for a Generating Facility may at the time of its application for initial registration or at any subsequent time apply for its registration of a Generating Facility with less than 10 MW total output as a Minor Generating Facility.

2.2.4.6, The NSPSO shall accede to such request and register the Generating Facility as a Minor Generating Facility if it is satisfied that, taking account of the location of the Generating Facility and its connection to the Transmission System, the Synchronization, De-synchronization and dispatch of the Generating Facility will not jeopardise the Reliability of the Bulk Electricity Supply System or any Zone thereof.

2.2.4.7, A Minor Generating Facility may subject to meeting the appropriate criteria also be an Intermittent Generating Facility.

2.2.4.8, For the sake of clarity, a Minor Generating Facility is a Generating Facility and subject to all applicable provisions of these Market rules except where explicitly excluded.

Load Displacement Generating Facilities

2.2.4.9, The Market Participant for a Generating Facility that is embedded within a Distribution System or Load Facility may at the time of its application for initial registration or at any subsequent time apply for its registration of such Generating Facility as a Load Displacement Generating Facility.

2.2.4.10, The NSPSO shall accede to such request and register the Generating Facility as a Load Displacement Generating Facility if it is satisfied that the operation of the Generating Facility is not expected under any normal operating conditions

Deleted: 30th September, 2006

to result in a net injection into the Transmission System, and that the absence of facility-specific scheduling information will not jeopardise the Reliability of the Bulk Electricity Supply System or any Zone thereof.

2.2.4.11, A Load Displacement Generating Facility may subject to meeting the appropriate criteria also be a Minor Generating Facility or an Intermittent Generating Facility.

2.2.4.12, For the sake of clarity, a Load Displacement Generating Facility is a Generating Facility and subject to all applicable provisions of these Market rules except where explicitly excluded.

Export Generating Facilities

2.2.4.13, The Market Participant for a Generating Facility other than a Load Displacement Generating Facility may at the time of its application for initial registration, and subject to the conditions set out below, apply for its registration as an Export Generating Facility.

2.2.4.14, The NSPSO shall accede to such request and register the Generating Facility as an Export Generating Facility if it is satisfied that the Generating Facility is associated with a facility-contingent export contract and firm export transmission reservations for substantially the full capability of the Generating Facility.

2.2.4.15, The Market Participant for a Generating Facility other than a Load Displacement Generating Facility may at any time and subject to the conditions set out below, apply for its re-classification as an Export Generating Facility to take effect no less than 5 years from the date of such application.

2.2.4.16, The NSPSO shall accede to such request and re-classify the Generating Facility as an Export Generating Facility on such effective date if it is satisfied at least six months in advance of the effective date that the Generating Facility is associated with a facility-contingent export contract and firm export transmission reservations for substantially the full capability of the Generating Facility.

Deleted: *30th September, 2006*

2.2.4.17, The Market Participant for an Export Generating Facility may apply for revocation of its classification as an Export Generating Facility at any time, and the NSPSO shall effect such revocation.

2.2.4.18, For the sake of clarity, an Export Generating Facility is a Generating Facility and subject to all applicable provisions of these Market rules except where explicitly excluded.

2.2.4.19, In applying for registration or re-classification of a Generating Facility as an Export Generating Facility, and unless the Facility is an Intermittent Generating Facility or a Minor Generating Facility, the Market Participant shall specify if the Export Generating Facility is to be classified as a Non-dispatchable Generating Facility.

2.2.5, Coming into effect

2.2.5.1, Facilities connected to the Transmission System prior to the effective date of these Market Rules shall except as noted in section 2.2.5.2 be deemed to be registered as follows.

a) All Generating Facilities directly connected to the Transmission System shall be deemed to be registered by NSPI PP.

b) All other Generating Facilities greater than 5 MW in capacity shall be deemed to be registered by NSPI PP.

c) All other Facilities shall unless otherwise designated by the NSPSO be deemed to be registered by NSPI Customer Operations division as Minor Load Displacement Generators.

d) The NSPSO may, following consultation with NSPI PP, designate Facilities as Intermittent Generating Facilities, as Minor Generating Facilities or as Load Displacement Generating Facilities.

2.2.5.2, Any Market Participant or applicant for accreditation may identify Facilities for which it will become the responsible Market Participant, and the NSPSO shall register such Facilities accordingly immediately on accreditation of that Market Participant.

Deleted: 30th September, 2006

2.2.6, Process for new or modified connections

2.2.6.1, No new Generating Facility may be Connected to the Transmission System except in accordance with the Standard Generation Interconnection Procedure, which forms exhibit 2 of the Transmission Tariff.

2.2.6.2, No existing Generating Facility Connected to the Transmission System may be significantly modified except in accordance with the Standard Generation Interconnection Procedure, which forms exhibit 2 of the Transmission Tariff. Significant modification shall include expansion or reduction of real or reactive power capability by more than the greater of 5% or 1 MW or 1 MVAR, changes to the excitation system, and changes to transmission-related protection systems.

2.2.6.3, No new or significantly modified Generating Facility may be connected to a Distribution System or Load Facility except in accordance with the Distribution Generator Interconnection Procedures and other requirements of the NSPSO as published in a Market Procedure setting out requirements for connection assessment of embedded Facilities.

2.2.6.4, In addition to assessments set out in the Generation Interconnection Procedure, the NSPSO shall assess a Special Locational Loss Factor applicable to any proposed new or significantly expanded Generating Facility as a basis for the application of a locational loss factor as set out in schedule 9 of the Transmission Tariff. This factor shall represent a reasonable estimate of the marginal loss on the incremental generation, averaged over the year, taking account of its location relative to existing generation, its location relative to the load pool, and its expected operating regime.

2.2.7, Continuing obligations

2.2.7.1, The Market Participant for a Facility shall ensure that the Facility continues to meet the standards set out for Connection.

2.2.7.2, The Market Participant for a Facility shall promptly report to the NSPSO any change in the information that has been provided to the NSPSO for Facility registration.

Deleted: 30th September, 2006

2.2.8, Disconnection

Voluntary Disconnection

2.2.8.1, The Market Participant for a Facility may apply to the NSPSO for permission to Disconnect a Facility from the Transmission System.

2.2.8.2, The NSPSO shall promptly review any such application, and shall grant permission unless the Disconnection would jeopardise the Reliability of the Bulk Electricity Supply System or any Zone thereof.

2.2.8.3, In any case where Disconnection would jeopardise Reliability, the Market Participant and the NSPSO shall negotiate in good faith for the ongoing provision by the Facility of services necessary to maintain Reliability of the Bulk Electricity Supply System or any relevant Zone thereof until the NSPSO can reasonably secure an alternative means to maintain Reliability.

NSPSO-directed Disconnection

2.2.8.4, The NSPSO may direct the Disconnection of a Facility from the Transmission System or the Distribution System on an immediate basis if the NSPSO considers that its continued Connection immediately jeopardises Reliability of the Bulk Electricity Supply System or any Zone thereof.

2.2.8.5, The NSPSO may direct the Disconnection of a Facility from the Transmission System as a compliance action as described in section 2.6 below.

2.2.8.6, In any event of directed Disconnection, the Facility shall remain Disconnected from the Transmission System until the NSPSO is satisfied with the corrective action, and permits re-Connection.

Deleted: 30th September, 2006

2.3, Wholesale and Renewable to Retail Market Advisory Committee

2.3.1, Appointment of a Wholesale and Renewable to Retail Market Advisory Committee

2.3.1.1, The NSPSO shall establish a Wholesale and Renewable to Retail Market Advisory Committee ("Advisory Committee"), for the purpose of securing advice on matters relating to the Nova Scotia wholesale and Renewable to Retail electricity market, as detailed in Appendix 2C.

2.3.1.2, The NSPSO shall appoint persons to the Advisory Committee in accordance with the terms of reference set out in Appendix 2C.

Deleted: Wholesale Market

2.3.1.3, The NSPSO may require any person appointed to the Advisory Committee to confirm agreement with the terms of reference set out in Appendix 2C.

Deleted: Wholesale Market

2.3.2, Meetings and support

2.3.2.1, The NSPSO shall arrange meetings of the Advisory Committee:

Deleted: Wholesale Market

a) at least once in every calendar quarter unless waived by unanimous agreement of all members of the Advisory Committee; and

Deleted: Wholesale Market

b) additionally as required for the conduct of the business of the Advisory Committee.

Deleted: Wholesale Market

2.3.2.2, The NSPSO shall provide the following support for the activities of the Advisory Committee as may be required from time to time for the due performance by the Advisory Committee of its functions:

Deleted: Wholesale Market

Deleted: Wholesale Market

a) administrative services, including the use of the NSPSO's support personnel where required;

b) facilities for meetings of the Advisory Committee;

Deleted: Wholesale

Deleted: Market

c) relevant information held by the NSPSO and analytical support, but not including Confidential Information.

Deleted: 30th September, 2006

2.3.2.3, The NSPSO shall Publish notice of the agenda for and minutes of meetings held by the Advisory Committee and the recommendations and reports of the Advisory Committee. Such Publication shall be effected from time to time as required to provide timely notice of developments.

Deleted: Wholesale Market

Deleted: Wholesale Market

2.3.3, Conduct of business

2.3.3.1, Subject to the provisions of this section 2.3 and of Appendix 2C, the Advisory Committee may establish, and may from time to time amend, the procedures and processes in accordance with which it will perform its functions. These procedures and processes, and any amendments thereto, shall be Published by the NSPSO.

Deleted: Wholesale Market

2.3.3.2, The Advisory Committee may consult with Market Participants and other interested persons in such manner and at such times at it considers appropriate for the due performance of its functions.

Deleted: Wholesale Market

2.3.3.3, Subject to paragraph 2.3.3.4, the Advisory Committee may establish subcommittees or working groups comprised of such persons, including members of the Advisory Committee, as the Advisory Committee considers appropriate for the due performance of its functions.

Deleted: Wholesale Market

Deleted: Wholesale Market

Deleted: Wholesale Market

2.3.3.4, Notwithstanding the establishment of a subcommittee or working group under paragraph 2.3.3.3, any recommendation respecting an amendment to the Market Rules or the review of a Market Procedure or of an Amendment to a Market Procedure shall be made by the Advisory Committee itself.

Deleted: Wholesale Market

2.3.4, Confidentiality

2.3.4.1, Members of the Advisory Committee shall enter into such confidentiality agreement as may be required by the NSPSO. The NSPSO may, on an exceptional basis, disclose Confidential Information to the Advisory Committee where such disclosure is necessary for the due performance by the Advisory Committee of its functions, it being understood that in most instances the disclosure of Confidential Information will not be required for this purpose.

Deleted: Wholesale Market

Deleted: Wholesale Market

Deleted: Wholesale Market

Deleted: 30th September, 2006

2.4, Administration of the Market Manual

2.4.1, General responsibility and authority

2.4.1.1, The NSPSO is responsible for maintaining and Publishing all components of the Market Manual, comprising Market Rules, standards, codes, Market Procedures and related documents.

2.4.1.2, The powers and responsibilities of the NSPSO as set out in this section are all subject to the authority retained by the Government of Nova Scotia in respect of, or associated with, changes in eligibility for participation in the markets.

2.4.2, Market Rules

2.4.2.1, Subject to paragraph 2.4.1.2, the NSPSO may amend the Market Rules in accordance with the process established under this sub-section 2.4.2, and subject to the jurisdiction of the Board which is described in sub-section 2.4.4.

2.4.2.2, The process for amending Market Rules shall:

a) permit any person including the NSPSO to propose and request consideration of an amendment;

b) provide evaluation of all proposed amendments in accordance with explicit criteria which reflect the object of the markets as set out in sub-section 1.1.2;

c) require the NSPSO to designate any proposed amendment as urgent if so directed by the Board in accordance with paragraph 2.4.4.3;

d) permit the NSPSO to designate any proposed amendment as urgent if, in the time taken to amend the Market Rules by the normal process and in the absence of an urgent rule amendment, either:

i) the Market Rules are in conflict with safety,

ii) there is a material threat to the Reliability of the Bulk Electricity Supply System or an Zone thereof that would be addressed by the urgent rule amendment, or

Deleted: 30th September, 2006

iii) there is a material threat to the integrity of the markets that would be addressed by the urgent rule amendment;

e) include prompt Publication of all amendment proposals, together with e-mail notification of such Publication to persons requesting such notification;

f) include stakeholder consultations prior to the making of any amendment except an urgent amendment;

i) stakeholder consultation shall include the opportunity for Advisory Committee and other stakeholder comment on any non-urgent amendment,

Deleted: Wholesale Market

ii) stakeholder consultation shall also include the opportunity for active Advisory Committee discussion of any material non-urgent amendment;

Deleted: Wholesale Market

g) include prompt Publication of stakeholder comments and of a record of Advisory Committee discussion, subject to the redaction of any information considered by the NSPSO to be Confidential;

Deleted: Wholesale Market

h) include the Publication of the NSPSO decision with supporting discussion of issues considered, opinions considered, and reasons for the conclusions reached, in respect of all proposed amendments;

i) require Publication of amendments at least 30 days before they come into effect, except for urgent amendments which may come into effect immediately on Publication;

j) permit accelerated Advisory Committee or stakeholder consultations prior to making any urgent rule amendment, and irrespective of any such accelerated stakeholder consultations, require stakeholder consultations including Advisory Committee discussions promptly to follow the coming into effect of any urgent amendment; and

Deleted: Wholesale Market

Deleted: Wholesale Market

k) require that NSPSO confirm or revise any urgent amendment following the stakeholder consultations which must take place following an urgent

Deleted: *30th September, 2006*

amendment; such confirmation or revision shall be subject to the same requirements for Publication and notice as apply to non-urgent amendments.

2.4.2.3, The NSPSO shall publish a Market Procedure describing its procedure for initiating, evaluating, stakeholdering, and making amendments to the Market Rules. This procedure shall:

a) reflect the process defined in paragraph 2.4.2.2;

b) include details for submission of proposed amendments, comments, etc; and

c) the NSPSO shall include reference to the process by which a person may appeal to the Board in respect of any Market Rule amendment.

2.4.3, Standards, codes and Market Procedures

2.4.3.1, The NSPSO may establish or adopt and may amend standards, codes and Market Procedures defining technical requirements, detailed calculations, and processes contemplated by these Market Rules.

2.4.3.2, Subject to paragraph 2.4.3.3 the process for establishing or adopting and for amending standards, codes and Market Procedures (collectively identified in this paragraph as changes) shall:

a) permit any person including the NSPSO to propose and request consideration of a change;

b) provide for evaluation of all such proposals in accordance with the objects of the markets and the provisions of the Market Rules;

c) recognise the authority of the Board;

d) permit the NSPSO to designate any proposed change as urgent if it is required for the implementation of an urgent Market Rule amendment or if in the time taken to effect the change by the normal process and in the absence of an urgent change, either:

Deleted: 30th September, 2006

i) the relevant standard, code or Market Procedure is in conflict with safety,

ii) there is a material threat to the reliability of the system that would be addressed by the urgent change, or

iii) there is a material threat to the integrity of the markets that would be addressed by the urgent change;

e) include prompt publication of all proposals for changes, together with e-mail notification of such publication to persons requesting such notification;

f) include stakeholder consultations prior to the making of all changes except urgent changes, where;

i) stakeholder consultation shall include the opportunity for Advisory Committee and other stakeholder comment on all non-urgent changes, and

Deleted: Wholesale Market

ii) stakeholder consultation may also include the opportunity for active Advisory Committee discussion of those non-urgent changes considered to have particular materiality to all or some Market Participants;

Deleted: Wholesale Market

Deleted: m

Deleted: p

g) require Publication of changes sufficiently in advance of their effective date to permit Market Participants to modify their systems and processes accordingly;

h) require stakeholder consultation including Advisory Committee discussion promptly to follow the coming into effect of any urgent change; and

Deleted: Wholesale Market

i) permit the NSPSO to confirm or revise any urgent change following such stakeholder consultations.

2.4.3.3, The provisions of paragraph 2.4.3.2 are not applicable to the establishment or adoption of standards, codes and Market Procedures made before 1 month after the coming into effect of the Market Rules.

Deleted: *30th September, 2006*

2.4.3.4, Each standard, code and Market Procedure shall indicate the NSPSO contact person responsible for the administration of that document.

2.4.4, Board intervention

2.4.4.1, In recognition of the Board's authority, the coming into effect of

a) any non-urgent Market Rule amendment,

b) any non-urgent establishment, adoption or amendment of a standard, code or Market Procedure,

c) any revision of an urgent Market Rule amendment, or

d) any revision of an urgently established, adopted or amended standard, code or Market Procedure,

shall immediately be stayed by the NSPSO if so ordered by the Board on its own motion or as a result of a person's appeal to the Board.

2.4.4.2, The NSPSO shall reconsider or cancel any Market Rule amendment or standard, code or Market Procedure or amendment thereto if so ordered by the Board on its own motion or as a result of a person's appeal to the Board.

2.4.4.3, The NSPSO shall amend any Market Rule or standard, code or Market Procedure if so ordered by the Board as a result of a conflict with either the provisions of the Legislation and Regulations, the reliable operation of the transmission system, or the provisions of a tariff approved by the Board.

2.4.4.4, The NSPSO shall include in the Market Procedure described in paragraph 2.4.2.3 a reference to the process by which a person may appeal to the Board in respect of any Market Rule amendment.

2.5, Temporary Waiver of Market Rules obligations

2.5.1, Granting of a Temporary Waiver

2.5.1.1, The NSPSO may grant a Temporary Waiver of a Market Rule to itself, or to a single Market Participant or a group of Market Participants if the NSPSO

Deleted: 30th September, 2006

considers that the particular application of the Market Rule is inconsistent with the object of the markets.

2.5.1.2, Such a Temporary Waiver may be granted in respect of a single Facility or a group of Facilities.

2.5.1.3, The NSPSO may in granting a Temporary Waiver impose conditions, the breach of which would render the Temporary Waiver cancelled.

2.5.1.4, Such a Temporary Waiver may be granted for any period up to 12 months.

2.5.1.5, A Market Participant may apply for extension of a Temporary Waiver up to a total including the original period of 24 months in order to allow time to implement a specific remedy.

2.5.1.6, There shall otherwise be no provision for renewal or extension of a Temporary Waiver.

2.5.2, Publication of a Temporary Waiver

2.5.2.1, The NSPSO shall publish details or any Temporary Waiver, including the reason for its decision to grant such a Temporary Waiver.

2.5.3, Appeal of Temporary Waiver

2.5.3.1, Any Market Participant may appeal to the NSPSO for review of any Temporary Waiver.

2.5.3.2, On receipt of such appeal, the NSPSO shall advise the Market Participant(s) granted the Temporary Waiver and shall provide an opportunity for that Market Participant(s) to provide additional information in response to the appeal.

2.5.3.3, The NSPSO shall then promptly review the Temporary Waiver, taking account of information provided by the appellate and by the Market Participant(s) granted the Temporary Waiver, and shall Publish its decision.

2.5.3.4, These Market Rules do not affect the rights of any Market Participant not satisfied by such review to appeal the Temporary Waiver to the Board.

2.5.3.5, These Market Rules do not affect the rights of any Market Participant to appeal directly to the Board in respect of a Temporary Waiver granted to the NSPSO, without the need for prior review by the NSPSO.

2.5.3.6, The NSPSO shall implement any order of the Board acting either on its own motion or as a result of a person's appeal to the Board, with respect to a Temporary Waiver.

2.5.4, Interaction with Market Rule amendments, tariffs, and Board orders

2.5.4.1, The NSPSO or a Market Participant may in accordance with subsection 2.4 propose an amendment to the Market Rules or any standard, code or Market Procedure invoked by the Market Rules for the purposes of making permanent, or making general, any Temporary Waiver.

2.5.4.2, The NSPSO's power to grant a Temporary Waiver shall not be used in conflict with any recent amendment to the Market Rules except where the particular impact of the amendment was unforeseen with respect to the matter of the Temporary Waiver.

2.5.4.3, The NSPSO's power to grant a Temporary Waiver shall not extend to provisions of any tariff approved by the Board or any order of the Board.

2.5.5, Market Procedure

2.5.5.1, The NSPSO may issue a Market Procedure governing the application process and other processes in respect of Temporary Waivers.

2.6, Compliance, and remedies for non-compliance

2.6.1, Compliance obligations

2.6.1.1, The NSPSO and each Market Participant is responsible to comply with these Market Rules at all times, and to maintain the management and systems to achieve such compliance.

Deleted: 30th September, 2006

2.6.2, Notice of inability to comply

2.6.2.1, In the event that the NSPSO identifies that it has failed to comply with a Market Rule, or will be unable to comply with a Market Rule, it shall promptly notify every affected Market Participant.

2.6.2.2, In the event that a Market Participant identifies that it has failed to comply with a Market Rule, or will be unable to comply with a Market Rule, it shall Promptly notify the NSPSO.

2.6.3, Graduated compliance actions

2.6.3.1, In the event that the NSPSO identifies that a Market Participant may have failed to comply with a Market Rule the NSPSO may communicate informally with the Market Participant to seek clarification of the circumstance.

2.6.3.2, Unless any such informal clarification indicates that there was no non-compliance, the NSPSO shall give notice of any alleged non-compliance to the Market Participant.

2.6.3.3, The NSPSO shall provide reasonable opportunity for the Market Participant to provide clarification of its actions and, if appropriate, any steps proposed to prevent recurrence.

2.6.3.4, In the event that the NSPSO then determines that there has been an event of non-compliance, the NSPSO shall give notice to the Market Participant of the non-compliance. Such notice shall include details of any actions being taken under any of paragraph 2.6.3.4 to 2.6.3.6.

2.6.3.5, In the event of a financial default by a Market Participant, the NSPSO may also require additional credit support, failing which the NSPSO may impose conditions on or may Suspend all or some of the Market Participant's activity.

2.6.3.6, In the event of either repeated non-compliance, or of major non-compliance that has jeopardised the Reliability of the Bulk Electricity Supply System or the integrity of the markets, the NSPSO may impose conditions on or may Suspend all or some of the Market Participant's activity, and may also direct that one or

Deleted: 30th September, 2006

more Facilities involved in the non-compliance be Disconnected from the Transmission System.

2.6.3.7, In addition to the remedies set out in paragraph 2.6.3.6, the NSPSO may assess and impose a financial penalty in accordance with guidelines set out in Appendix 2.B of these Market Rules.

2.6.3.8, In the event that a Market Participant demonstrates material disregard of its obligations by repeated financial defaults or major non-compliances, the NSPSO may Terminate the market participation rights of that Market Participant.

2.6.3.9, Suspension or Termination shall only come into effect following notice by the NSPSO to the Market Participant, and a reasonable opportunity for the Market Participant to be heard by the NSPSO all as provided for in a Market Procedure which will have due regard for terms of the Transmission Tariff.

2.6.3.10, In the event of Disconnection, the NSPSO shall provide notice and an opportunity to be heard but, if the NSPSO considers that delay in effect of Disconnection would jeopardise Reliability of the Bulk Electricity Supply System or a Zone thereof, the Disconnection shall, in accordance with the powers of the Transmission Provider under the Transmission Tariff and related agreements, have immediate effect pending such hearing.

2.6.3.11, In the event of direction from the Board following appeal by a Market Participant, the NSPSO shall grant such temporary relief or modify financial penalties, Suspension, Termination or Disconnection as directed by the Board.

2.7, Market Monitoring

2.7.1, Market monitoring responsibilities

2.7.1.1, The NSPSO shall collect, maintain and analyse data necessary for monitoring the operation of the markets.

2.7.1.2, The NSPSO shall provide to the Board the data and analysis directed by the Board for purposes of the Board's market surveillance.

Deleted: 30th September, 2006

2.7.1.3, The NSPSO shall perform or assist in any investigations directed by the Board.

2.7.1.4, The NSPSO is under no obligation to disclose to a Market Participant the existence of any analysis or any Board-directed investigation it is undertaking.

2.7.1.5, In the event that the Board directs the NSPSO to provide data held by a Market Participant and not by the NSPSO, the NSPSO shall direct the relevant Market Participant to provide the data direct to the Board.

2.7.1.6, The NSPSO may in the course of its operations identify concerns, anomalies or apparent abuses of the markets, in which case it shall report these to the Board for its consideration and any action.

2.7.2, Market Participant obligations

2.7.2.1, In then event that the NSPSO directs the provision of additional information to the Board for purposes of the Board's market surveillance, the Market Participant shall Promptly provide such information direct to the Board, in the form specified by the Board.

2.7.2.2, The Market Participant may identify information as confidential.

2.7.2.3, In the event of any dispute about the need for certain information, the Market Participant may seek to resolve this directly with the Board.

2.8, Disputes

2.8.1, Correction of errors

2.8.1.1, Any Market Participant or the NSPSO shall, promptly on identifying any apparent error, notify other impacted parties to seek correction.

2.8.2, Dispute resolution procedures

2.8.2.1, Except as otherwise provided in respect of metering disputes, any disputes under the Market Rules shall be subject to the dispute resolution procedures set out in the Transmission Tariff. In particular:

Deleted: 30th September, 2006

a) internal dispute resolution, Transmission Tariff section 12.1;

b) external arbitration resolution, Transmission Tariff section 12.2;

c) arbitration decisions, Transmission Tariff section 12.3;

d) costs, Transmission Tariff section 12.4; and

e) rights under the *Public Utilities Act*, Transmission Tariff section 12.5

Deleted: .

2.9, Confidential Information and Market Information

2.9.1, General confidentiality requirements

2.9.1.1, Each Market Participant and the NSPSO shall keep confidential all Confidential Information that it receives, and shall establish procedures that will protect the confidentiality of such Confidential Information and prevent its distribution other than to those individuals requiring access to such information in the fulfilment of their responsibilities.

2.9.1.2, The NSPSO's procedures shall comply with the requirements of the Standards of Conduct attached to the Transmission Tariff.

2.9.1.3, Except as permitted under paragraph 2.9.2.2, any Market Participant or the NSPSO that is required by law to disclose Confidential Information to a third party shall, before making such disclosure, notify the originator of the Confidential Information and, to the extent permitted by such law, provide an opportunity for the originator to intervene to stop or limit such disclosure.

2.9.1.4, These general confidentiality requirements are supplemented in respect of Connected Generating Facilities by the specific requirements of the Generator Interconnection Agreement.

2.9.2, Provision of data to the Board

2.9.2.1, The NSPSO shall file with the Board all Market Rules, all Market Procedures, standards and codes given force by the Market Rules, and all amendments thereof.

Deleted: 30th September, 2006

2.9.2.2, The NSPSO may, without notice to any Market Participant, provide to the Board any Confidential Information directed by the Board to be provided for purposes of market surveillance or investigation.

2.9.3, Accidental disclosure

2.9.3.1, In the event that any Market Participant or the NSPSO accidentally discloses Confidential Information to another party (including to its unauthorised employees), it shall immediately notify the originator of the Confidential Information and shall collaborate in limiting and mitigating the impact of such accidental disclosure.

2.9.3.2, If the party making accidental disclosure is the NSPSO or any division of NSPI, then actions shall be governed by the Standards of Conduct attached to the Transmission Tariff.

2.9.4, Publication

2.9.4.1, The NSPSO shall Publish certain market information. This shall include information identified for Publication in these market rules, and may include additional reports, notices and aggregated market information as the NSPSO considers appropriate.

2.9.4.2, Such Publication shall be prompt, taking into account the nature of the information to be Published.

2.9.5, Market information

2.9.5.1, Confidential Information in respect of market administration generally includes:

a) credit support requirements and fulfillment thereof;

b) compliance actions other than those listed in paragraph 2.9.5.2; and

c) details of dispute resolution, other than those listed in paragraph 2.9.5.2.

2.9.5.2, The NSPSO shall Publish information in respect of market administration including:

Deleted: *30th September, 2006*

a) Market Participant list including for each the classes of participation, and addresses for business contacts and the service of notice;

b) Temporary Waivers;

c) compliance actions comprising one or more of:

   i) imposing conditions on, or suspending or limiting, market participation by a Market Participant,

   ii) imposing a financial penalty,

   iii) Disconnecting a Facility, and

   iv) Terminating market participation rights of a Market Participant;

d) the existence of external dispute resolution process and identities of the parties; and

e) the outcome of external dispute resolution including identities of the parties, the matter of the dispute and the outcome.

Deleted: -
Deleted:
Deleted:
Deleted: -
Deleted:
Deleted:
Deleted:
Deleted:
Deleted: *WMAC*
Deleted: ,
Deleted: *30th September, 2006*

Appendix 2C

Wholesale and Renewable to Retail Market Advisory Committee

Terms of Reference

2C.1 Purpose and scope of Advisory Committee

Deleted: **Wholesale Market**

2C.1.1, The Advisory Committee is established to provide advice to the NSPSO in matters concerning the Nova Scotia wholesale and Renewable to Retail electricity markets, and in particular:

Deleted: Wholesale Market

a) The Advisory Committee will be the primary but not exclusive forum for:

Deleted: Wholesale Market

i) active consultation with stakeholders on proposed amendments to Market Rules, as required in paragraph 2.4.2.2 (f) and as required following an urgent amendment in paragraph 2.4.2.2 (j);

ii) any accelerated consultation with stakeholders on proposed amendments to Market Rules, as permitted in respect of urgent Market Rule amendments in paragraph 2.4.2.2 (j);

iii) any active consultation with stakeholders on proposed establishment, adoption or amendment to standards, codes or Market Procedures, as permitted in paragraph 2.4.3.2 (e) and paragraph 2.4.3.2 (g), and on the electronic interface systems used by Market Participants;

iv) any active consultation with stakeholders on other wholesale and Renewable to Retail electricity market issues identified by the NSPSO or introduced by committee members or other stakeholders.

b) The Advisory Committee will at the discretion of the NSPSO provide an opportunity for discussion of matters relating to the implementation of the Transmission Tariff or of possible changes to the Transmission Tariff that are under consideration by the NSPSO in preparation for application to the Board.

Deleted: Wholesale Market

2C.1.2, The Advisory Committee is excluded from consideration of individual participant transactions with the NSPSO except to the extent that such consideration is a necessary and appropriate illustration in the context of paragraph 2C 1.1.

2C.1.3, The Advisory Committee is excluded from consideration of matters of Government or Board jurisdiction except to the extent that the Government or the Board requests consideration by the Advisory Committee of a particular matter.

2C.2 Membership

2C.2.1, Membership of the Advisory Committee shall comprise

a) one representative of the NSPSO who shall be chair;

b) one representative of NSPI PP;

c) one representative of NSPI Customer Service;

d) one representative of independent generators;

e) one representative of those eligible to be Market Participants as wholesale loads; and

f) one representative of those otherwise eligible to be Transmission Customers.

2C.2.2, The Nova Scotia Department of Energy ("Department of Energy") and the Board may each appoint an observer to the Advisory Committee.

2C.2.3, Each member and observer may have one alternate who may attend and participate in any meeting in place of the member or observer.

2C.2.4, The members appointed under sub-paragraphs 2C.2.1 (a), (b) and (c) may be referred to as the NSPI members.

2C.2.5, The members appointed under sub-paragraphs 2C.2.1 (d), (e) and (f) may be referred to as the independent members.

Deleted: -
Deleted:
Deleted:
Deleted: -
Deleted:
Deleted:
Deleted:
Deleted:
Deleted: *WMAC*
Deleted: ,
Deleted: *30th September, 2006*
Deleted: Wholesale Market
Deleted: Wholesale Market
Deleted: Wholesale Market
Deleted: Wholesale Market
Deleted: c

Deleted: -
Deleted:
Deleted:
Deleted: -
Deleted:
Deleted:
Deleted:
Deleted:
Deleted: *WMAC*
Deleted: ,
Deleted: *30th September, 2006*

2C.3 Appointment and term

2C.3.1, The NSPSO shall nominate and appoint its representative and any alternate.

2C.3.2, The NSPSO shall appoint a representative of each of NSPI PP and NSPI Customer Service as nominated by each of those NSPI divisions, and any alternates similarly nominated.

2C.3.3, The NSPSO shall appoint a member representing each other group in accordance with nomination by the Department of Energy, and any alternate similarly nominated.

2C.3.4, In the event that the Department of Energy makes no nomination of a member, an alternate, or both, that position shall remain vacant until such time as the Department of Energy makes such nomination.

2C.3.5, Subject to paragraphs 2C.3.6 to 2C.3.11, each member of the Advisory Committee and each alternate shall be appointed for a term of 3 years and shall be eligible for reappointment for one or more additional terms of no more than three years each. In no event shall a member of the Advisory Committee or alternate, other than the representative of the NSPSO, be eligible for reappointment for any period that would result in the person holding office:

Deleted: Wholesale Market

Deleted: Wholesale Market

a) as member for a period of more than 7 years

b) as alternate for a period of more than 7 years

c) as member and alternate combined for a period of more than 10 years

2C.3.6, The term of a member of Advisory Committee or alternate appointed to replace a member or alternate whose term had not yet expired shall be the unexpired term of the predecessor member or alternate.

Deleted: the Wholesale Market

2C.3.7, The term of a member of the Advisory Committee or alternate appointed under paragraph 2C.3.4 after the commencement of the intended term shall be the unexpired portion of the intended term.

Deleted: Wholesale Market

2C.3.8, In order that the terms of appointment be staggered, the initial terms of appointment of each initial member of the Advisory Committee and their alternates shall be as follows:

a) for each member and alternate appointed in accordance with sub-paragraphs 2C.2.1 (a), (b) and (e), 3 years; and

b) for each member and alternate appointed in accordance with sub-paragraphs 2C.2.1 (c), (d) and (f), 18 months.

2C.3.9, A member of the Advisory Committee or alternate ceases to hold office when he or she:

a) dies;

b) resigns;

c) for each NSPI member and alternate, when he or she cease to be employed or engaged by the NSPSO or relevant division of NSPSI; or

d) is removed in accordance with section 2C.3.9.

2C.3.10, An independent member or alternate whose employment or other circumstances changes shall promptly

a) notify the Advisory Committee;

b) notify the Department or Energy;

c) provide to the Department of Energy information that will enable the Department of Energy to determine whether the member or alternate can continue adequately to represent the interests for which he or she was appointed; and

d) unless the Department of Energy confirms that it considers that the member or alternate can continue adequately to represent the interests for which he or she was appointed, resign from the appointment to the Advisory Committee.

Deleted: -
Deleted:
Deleted:
Deleted: -
Deleted:
Deleted:
Deleted:
Deleted:
Deleted: *WMAC*
Deleted: ,
Deleted: *30th September, 2006*
Deleted: Wholesale Market
Deleted: Wholesale Market
Deleted: Wholesale Market
Deleted: Wholesale Market

2C.3.11, The NSPSO may remove any member of the Advisory Committee or alternate from office:

a) for cause, including a breach of fiduciary duty or confidentiality; or

b) where the person ceases to be qualified in accordance with sub-section 2C.4.

2C.3.12, In the event of any actual or forthcoming vacancy on the Advisory Committee, the NSPSO shall notify the NSPI division responsible or the Department of Energy as appropriate in order to secure the nomination of a replacement member or alternate.

2C.3.13, In the event of vacancy of a membership of the Advisory Committee, the alternate for that position shall act as member pending the appointment of a replacement member. Unless precluded by paragraph 2C.3.4, the alternate shall be eligible for nomination as the replacement member.

2C.4 Qualifications of members and alternates

2C.4.1, Each member and alternate is expected to:

a) understand the business of, and be capable or representing the interests of, the organisation or group that he or she is appointed to represent;

b) develop an understanding of the operation of the wholesale and Renewable to Retail electricity markets, with an appreciation of the technical considerations that underlie the operation of the Bulk Electricity Supply System;

c) commit the time and effort necessary to participate fully as a member, or sufficiently as an alternate; and

d) be free of material conflicts of interest that would preclude or limit full participation and representation.

2C.4.2, The following persons are not qualified for appointment to the Advisory Committee, either as member or alternate:

Deleted: -
Deleted:
Deleted:
Deleted: -
Deleted:
Deleted:
Deleted:
Deleted:
Deleted: *WMAC*
Deleted: ,
Deleted: *30th September, 2006*
Deleted: Wholesale Market
Deleted: Wholesale Market
Deleted: Wholesale Market
Deleted: Wholesale Market

Deleted: -
Deleted:
Deleted:
Deleted: -
Deleted:
Deleted:
Deleted:
Deleted:
Deleted: *WMAC*
Deleted: ,
Deleted: *30th September, 2006*

a) any person less than 18 years of age;

b) any person of unsound mind, having been so found by a court in Canada or elsewhere;

c) any person who is not an individual;

d) any person who has the status of a bankrupt;

e) any person who is an employee of the Government of Nova Scotia, and

f) any person who is disqualified by section 2C.4.3.

2C.4.3 A person shall not be appointed to the Advisory Committee as an independent member or alternate if the person is a director, officer, employee or other representative of a person who has, or whose Affiliate has, a director, officer, employee or other representative who is a member of the Advisory Committee or alternate, except that this provision shall not apply in respect of a member and alternate representing the same group.

Deleted: Wholesale Market

Deleted: Wholesale Market

2C.5 Procedures and processes

2C.5.1, In accordance with paragraph 2.3.3.1, the Advisory Committee may establish, and may from time to time amend, the procedures and processes in accordance with which it will perform its functions.

Deleted: Wholesale Market

2C.5.2, The Advisory Committee shall give due regard to the reasonable needs of its members with respect to notice of meetings, as well as to the occasional need for expedited meetings to address issues in a timely manner.

Deleted: Wholesale Market

2C.5.3, The adoption of procedures and processes requires the consent of the majority of the committee, including at least half of the independent members (or if appropriate their alternates).

2C.5.4, The Advisory Committee shall recognise the advisory nature of the committee's purpose and scope, and shall therefore provide for the recording and reporting of dissenting views as well as of consensual conclusions.

Deleted: Wholesale Market

Deleted: -
Deleted:
Deleted:
Deleted: -
Deleted:
Deleted:
Deleted:
Deleted:
Deleted: *WMAC*
Deleted: ,
Deleted: *30th September, 2006*

2C.6 Meetings

2C.6.1, Meetings shall take place in Halifax, in facilities to be provided by the NSPSO.

2C.6.2, Meetings will normally be held in private, with administrative support provided by the NSPSO and with the support and assistance of experts as necessary. The chair may determine that all or part of a meeting should be open to wider observation or wider participation within the context of broader stakeholdering of an issue.

2C.6.3, The business of meetings is generally not confidential, but the chair may identify material confidentiality relating to certain issues or information, in which case all members and other attendees shall be bound by such confidentiality.

2C.6.4, Members of the Advisory Committee are expected to make all reasonable efforts to participate in all meetings but, if they are unable to participate, may be represented by their alternates.

Deleted: Wholesale Market

2C.6.5, Department of Energy and Board observers shall be invited to observe meetings, and may at the discretion of the chair be invited to make comment on matters under discussion.

2C.6.6, Meeting notices, agendas, preparatory materials, presentation materials and minutes will be made public subject to redaction in the unusual event of confidentiality requirements.

2C.6.7, The committee will establish its own processes to govern issues such as telephone participation, non-member presentations, declaration of conflicts, etc.

2C.7 Remuneration and expenses

2C.7.1, There is no remuneration for membership or participation in the Advisory Committee.

Deleted: Wholesale Market

2C.7.2, Each member and alternate is responsible for his or her own expenses arising from membership and participation.

2C.7.3, These provisions do not limit members' or alternates' arrangements with their employers or the groups they represent.

Deleted: -

Deleted:

Deleted:

Deleted: -

Deleted:

Deleted:

Deleted:

Deleted:

Deleted: *WMAC*

Deleted: ,

Deleted: *30th September, 2006*

Deleted: 30th September, 2006

3, Reliability Planning Requirements

3.0, Description

This chapter sets out the reliability-related obligations of all parties in the planning timeframe. These rules apply to the NSPSO, to NSPI transmission, and to Market Participants who are responsible for Facilities registered in the market, and to Connection Applicants.

3.1, Reliability planning responsibilities

3.1.1, NSPSO responsibilities

3.1.1.1, The NSPSO is responsible within NSPI for directing the Reliable operation of the Bulk Electricity Supply System in Nova Scotia in fulfillment of NSPI's obligations under:

a) the Legislation and Regulations;

b) orders of the Board, including in respect of General Reliability Standards, (including policies and codes) prescribed by such orders;

c) except as superseded by order of the Board, NSPI's membership agreement in NPCC, the General Reliability Standards, (including policies and codes) associated therewith: and

d) NSPI's interconnection agreement with the New Brunswick System Operator (NBSO), including in particular those obligations arising in support of the NBSO's function as Reliability Coordinator for the interconnected system in the Maritime region.

3.1.1.2, The NSPSO is responsible for:

a) fulfillment of its obligations under the Market Rules;

b) identification of any amendments to Market Rules or changes in standards, codes and Market Procedures required to reflect changes in

Deleted: 30th September, 2006

General Reliability Standards, (including policies and codes), and the Maritime region requirements; and

c) general planning and coordination for the Reliability of the Bulk Electricity Supply System.

3.1.2, Other NSPI division responsibilities

3.1.2.1, NSPI PP, NSPI Customer Operations and NSPI Customer Service divisions are responsible within NSPI for their respective obligations arising from:

a) the Legislation and Regulations;

b) orders of the Board, including in respect of general reliability standards, (including policies and codes) prescribed by such orders;

c) except as superseded by order of the Board, NSPI's membership agreement in NPCC, and the General Reliability Standards, (including policies and codes) associated therewith;

d) NSPI's interconnection agreement with the NBSO,

e) the Market Rules.

3.1.3, Other Market Participant responsibilities

3.1.3.1, Other Market Participants are responsible for their compliance with:

a) the Market Rules;

b) orders of the Board, including in respect of General Reliability Standards, (including policies and codes) prescribed by such orders; and

c) except as superseded by order of the Board, the General Reliability Standards, (including policies and codes) established by NERC and NPCC.

Deleted: 30th September, 2006

3.2, Technical Standards

3.2.1, General Reliability Standards

3.2.1.1, General Reliability Standards are those established by NERC, NPCC or by order of the Board, and include all associated policies and codes.

3.2.2, Specific standards

3.2.2.1, The NSPSO may establish technical standards under its authority in section 1.5.

3.2.2.2, Such standards may address the application of General Reliability Standards in Nova Scotia, or may address other matters pertaining to the operation of the Bulk Electricity Supply System or of the wholesale and Renewable to Retail electricity markets.

3.2.2.3, The NSPSO may amend such technical standards in accordance with the process described in section 2.4.

3.2.2.4, No such technical standard or amendment shall be in conflict with the General Reliability Standards.

3.2.2.5, The NSPSO shall Publish all such technical standards, and shall Publish a list of such standards including the latest revision date of each.

3.2.2.6, Market Participants are responsible for the compliance of their Facilities with such standards established by the NSPSO, except as permitted by Temporary Waiver granted in accordance with section 2.5.

3.2.2.7, The NSPSO may also incorporate technical standards into the standard Generator Interconnection Agreement or the Network Operating Agreement attached to the Transmission Tariff. Responsibility for compliance with such standards is established in those agreements.

Deleted: 30th September, 2006

3.3, Forecasts and assessments

3.3.1, Timing and scope of forecasts and assessments

3.3.1.1, The NSPSO shall make and Publish 18 month forecasts and assessments of system capacity and adequacy by the end of each April and October each year for the periods starting in May and November respectively. This 18 month forecast and assessment shall have an 18 month time horizon and weekly granularity. This 18 month forecast and assessment is intended to provide a basis for outage planning and coordination, and for medium term Market Participant operational planning.

3.3.1.2, The NSPSO shall file with the Board its 10 year energy and demand forecast by the end of April each year for the 10 year period beginning in the following January.

3.3.1.3, The NSPSO shall make and Publish its 10 year forecast and assessment of system capacity and adequacy by the end of June each year for the period beginning in the following January. This 10 year forecast and assessment shall have a 10 year time horizon and monthly granularity. This 10 year forecast and assessment shall contain the information necessary to provide a basis for identification of system-wide or location-specific shortfalls in capability as a basis for planning investment in DSM, generation and transmission.

3.3.1.4, The NSPSO shall, jointly with the NBSO and Maritime Electric Company Limited, prepare a triennial "5 year assessment" of the Maritime area in accordance with the requirements of the General Reliability Standards.

3.3.2, Inputs from others

3.3.2.1, The NSPSO shall perform all of these forecasts and assessments with inputs from NSPI Customer Operations in respect of the Transmission System, Generation Market Participants, Load Market Participants, Licenced Retail Supplier Market Participants, and Connection Applicants.

Deleted: 30th September, 2006

3.3.2.2, The NSPSO shall specify to Market Participants and Connection Applicants, directly or in a Market Procedure, the information it requires and the date by which it requires such information.

3.3.2.2, Market Participants and Connection Applicants shall provide the required information to the NSPSO by the dates specified.

3.3.3, Content of forecasts and assessments

3.3.3.1, The forecasts will reflect the NSPSO's expectations of firm and interruptible demand and energy requirements taking account of information provided by others and of established DSM programs, and may reflect a range of such expectations.

3.3.3.2, The assessments will reflect the requirement to maintain reserves at the level required of NSPI as its contribution to Maritime area fulfillment of the General Reliability Standards.

3.3.3.3, The assessments will reflect the impacts of transmission and generation investments committed in accordance with approved NSPI system plans, generation and DSM investments committed by Market Participants and planned retirements or capability changes advised to the NSPSO.

3.3.3.4, The 18 month assessments will reflect the Outage Plans of NSPI Customer operations in respect of the Transmission System and of other Market Participants in respect of Generating Facilities as notified to the NSPSO.

3.3.3.5, The 10 year assessments will indicate the needs for new investments and the extent to which existing plans and Connection Applications would satisfy such needs.

3.3.4, Imports, exports and Export Generating Facilities

3.3.4.1, The NSPSO shall, subject to its being satisfied as to the nature of the commitments, take account in its assessments of long term firm import contracts that are backed by firm transmission rights or reservations as contributing to the Adequacy of the Bulk Electricity Supply System.

Deleted: 30th September, 2006

3.3.4.2, The NSPSO shall take account of long term firm export contracts as adding to its energy and demand forecasts.

3.3.4.3, The NSPSO shall reflect in its forecasts and assessments the offsetting effects with respect to energy and demand (but not necessarily with respect to transmission or Ancillary Services) of an Export Generating Facility and its associated export contract.

3.4, NSPSO system planning

3.4.1, Responsibility of the NSPSO

3.4.1.1 The NSPSO is responsible for the preparation of the NSPSO system plan and the coordination of inputs thereto. The NSPSO shall specify information needed from NSPI divisions and other Market Participants and Connection Applicants, shall set the deadlines for submission of such information, and shall establish the parameters and methodology to be used in evaluation of alternatives.

3.4.1.2, The NSPSO shall reflect in the NSPSO system plan the information received from NSPI divisions and from other Market Participants and Connection Applicants.

3.4.1.3, The NSPSO shall evaluate the information received from NSPI divisions and from other Market Participants and Connection Applicants in order to develop the NSPSO system plan.

3.4.1.4, Nothing in these Market rules or the NSPSO system plan affects the requirement for capital expenditure approval by the Board pursuant to the provisions of the *Public Utilities Act.*

3.4.2, Scope of the NSPSO system plan

3.4.2.1, The NSPSO system plan will address:

a) transmission investment planning;

Deleted: 30th September, 2006

b) DSM programs operated by NSPI Customer Service division or others;

c) NSPI generation planning for existing Facilities, including retirements as well as investments in upgrades, refurbishment or life extension;

d) new Generating Facilities committed in accordance with previous approved NSPSO system plans;

e) new Generating Facilities planned by Market Participants or Connection Applicants other than NSPI;

Deleted: ,

Deleted: and

f) requirements for additional DSM programs and / or generating capability (for energy or ancillary services), and

Deleted: .

g) load transitioning to non-NSPI supply.

3.4.3, Planning horizon and scope

3.4.3.1, The purpose of the plan is to set out planned system developments, and to identify particular major investment decisions and other investment plans which are expected to be subject to Board approval, and that would require to be approved by the Board within 18 months of plan completion date, within the context of the system requirements over at least the next 10 years.

3.4.3.2, The plan shall include identification of explicit major decisions to undertake certain investments, and of implicit decisions which may constrain options for future decisions.

3.4.3.3, The plan shall include all significant transmission system upgrades that are planned or expected to be required in service within 5 years of the plan completion date.

3.4.4, Planning criteria

3.4.4.1, In developing its system plan the NSPSO shall have due regard to:

a) reliability of the Bulk Electricity Supply System including in particular its Adequacy in accordance with General Reliability Standards;

Deleted: 30th September, 2006

b) compliance with environmental legislation and regulations; and

c) economic evaluation of options.

3.4.4.2, The NSPSO shall not discriminate amongst options on the basis of ownership.

3.4.5, Confidentiality, Publication and Board process

3.4.5.1, The NSPSO shall submit the draft NSPSO system plan to the Board for the Board's public comment process and for any Board review, and shall at the same time Publish the plan.

3.4.5.2, NSPI PP or Market Participants or Connection Applicants for proposed new generation projects may request to NSPSO that certain information be treated as Confidential Information if its Publication would be expected to be prejudicial to commercial interests beyond the context of the NSPSO system plan.

3.4.5.3, NSPSO shall evaluate any such request for confidentiality and shall:

a) determine the extent of such information essential to enable readers to understand the NSPSO system plan and the evaluation of options undertaken in preparation of that plan;

b) inform the provider of the information the details of information that the NSPSO considers to be thus an essential part of the Published system plan;

c) seek to resolve any difference of opinion over appropriate confidentiality with the provider of the information; and

d) include essential information in the Publication of the NSPSO system plan.

3.4.5.4, The NSPSO shall file additional supporting Confidential Information with the Board as an appendix to the draft NSPSO system plan, including the request from the relevant party that the Board treat this information as confidential.

Deleted: 30th September, 2006

3.4.5.5, Following the completion of the Board's public comment process and of any review by the Board, the NSPSO may update the plan and shall publish the final version of the NSPSO system plan.

3.4.6, Timelines

3.4.6.1, Subject to any contrary order of the Board, the NSPSO shall submit the draft NSPSO system plan to the Board for the Board's public comment process and for any Board review, and shall Publish the draft plan each year by the end of June.

3.5, Outage management

3.5.1, Responsibilities and basic obligations

3.5.1.1, The NSPSO shall coordinate Transmission System and Generating Facility Outages to maintain the Reliability of the Bulk Electricity Supply System, including in particular the Adequacy of the system.

3.5.1.2, Except as noted in paragraphs 3.5.1.3 and 3.5.1.4, NSPI Customer Operations in respect of the Transmission System and Generation Market Participants in respect of their Generating Facilities shall not undertake any Outage except a Forced Outage, without:

a) NSPSO approval of the Outage Plan, and

b) NSPSO approval to commence the Outage.

3.5.1.3, The Generation Market Participant for an Export Generating Facility shall advise the NSPSO of its Outage Plans in respect of such Export Generating Facility, and may undertake such planned Outages subject to only the normal requirement for approval to De-synchronize as set out in section 4.7.

3.5.1.4, The Generation Market Participant for an Minor Generating Facility shall advise the NSPSO of its Outage Plans in respect of such Minor Generating Facility, and may undertake such planned Outages in accordance with such notification.

Deleted: 30th September, 2006

3.5.2, Outage coordination principles

3.5.2.1, The NSPSO shall coordinate and approve Outage Plans in accordance with the following principles:

a) The NSPSO shall not approve any Outage Plan that would jeopardise the Reliability of the Bulk Electricity Supply System or any Zone thereof except to the extent that this is unavoidable.

b) The NSPSO shall seek to facilitate coordination of Outage Plans among the NSPI Customer Operations in respect of the Transmission System, and Generation Market Participants, subject to confidentiality constraints and the willingness of the NSPI Customer Operations in respect of the Transmission System and of Generation Market Participants.

c) In facilitating coordination among NSPI Customer Operations in respect of the Transmission System and Generation Market Participants, the NSPSO shall support efforts to optimise economic as well as Reliability impacts.

d) The NSPSO shall not discriminate amongst Facility Outage Plans on the basis of Facility ownership or Generating Market Participant.

3.5.3, Outage coordination process, and Outage Plan approval and rejection

3.5.3.1, The NSPSO shall establish the process for coordination and approval of Outage Plans in accordance with the following framework, and shall publish a Market Procedure setting out this process.

3.5.3.2, The NSPSO shall publish a calendar setting out deadlines for each stage in the annual Outage planning cycle, including the "year" to which it applies.

Equipment, Facility and Outage classification

3.5.3.3, The NSPSO shall include in its Market Procedure the classification for Outage planning purposes of transmission circuits and elements, and Generating

Deleted: 30th September, 2006

Facilities and elements, into those having major, intermediate or only local impact.

3.5.3.4, The NSPSO shall include in its Market Procedure the classification of Outages depending on classification of the equipment or Generating Facility and the planned duration of the Outage.

Information required

3.5.3.5, The NSPSO shall include in its Market Procedure the information to be included in an Outage Plan submission, which shall include information relating to the opportunity for recall.

Annual Outage planning cycle

3.5.3.6, The NSPSO annual Outage planning cycle shall comprise:

a) NSPI Customer Operations shall Publish its preliminary plan for at least all major and to the extent known, intermediate, Outages in the Transmission System.

b) NSPI PP and other Generation Market Participants for Generating Facilities shall advise the NSPSO of their preferred Outage Plans for all major and to the extent known, intermediate, Outages, as well as any identified conflicts with the preliminary Transmission System Outage Plan.

c) NSPI Customer Operations shall communicate with Load Market Participants, with other wholesale customers of NSPI, and with other large customers of NSPI in order to identify any conflicts between such parties' requirements and the preliminary Transmission System Outage Plan, and shall advise the NSPSO of any consequent changes to its preliminary Transmission System Outage Plan.

d) The NSPSO shall review the preliminary Transmission System Outage Plan and the Generating Facility Outage Plans, and shall identify any Outage Plans:

Deleted: 30th September, 2006

i) that cannot be approved without avoidable jeopardy to the Reliability of the Bulk Electricity Supply System or any Zone thereof;

ii) for which approval would be contingent on the ability to recall the equipment or Generating Facility from Outage; or

iii) for which better coordination would be expected to result in less economic loss.

e) The NSPSO shall notify NSPI Customer Operations in respect of the Transmission System, NSPI PP and other impacted Generation Market Participants, of any of their Outage Plans that cannot be approved and of those Outage Plans that could be better coordinated.

f) To the extent permitted by the respective Generation Market Participants (including NSPI PP) the NSPSO shall seek to mediate or to facilitate discussion amongst the impacted parties.

g) NSPI Customer Operations in respect of the Transmission System and Generation Market Participants (including NSPI PP) may submit revised Outage Plans.

h) The NSPSO shall review the revised Transmission System and Generating Facility Outage Plans, and shall identify and reject any Outage Plans that cannot be approved without avoidable jeopardy to the Reliability of the Bulk Electricity Supply System or any Zone thereof. .

i) The NSPSO shall approve all Outage Plans that can be approved without avoidable jeopardy to the Reliability of the Bulk Electricity Supply System or any Zone thereof.

j) In the event of conflict between Outage Plans, the NSPSO shall reject first that Outage Plan for which NSPI Customer Operations in respect of the Transmission System or the Generation Market Participant has shown the least commitment to collaborative rescheduling.

k) In the event that, in the judgment of the NSPSO, the impacted parties are equally committed to collaborative re-scheduling, the NSPSO shall reject

Deleted: 30th September, 2006

first the Outage Plan whose rejection would in its opinion have the least total economic impact.

l) The NSPSO may make its approval of an Outage Plan contingent on the recallability of equipment from Outage on certain terms.

Changes and additional Outages

3.5.3.7, Any Outage Plan rejected in accordance with the process described in paragraph 3.5.3.6 above may, at the request of NSPI Customer Operations or the Generation Market Participant, stand as an open request, in which case it shall be evaluated in advance of Outage Plans submitted later.

3.5.3.8, Outage Plans submitted to the NSPSO after the deadline for submissions under paragraph 3.5.2.2 above shall be evaluated in the order received.

3.5.3.9, Any material change to an approved Outage Plan shall be evaluated as a new Outage Plan.

3.5.3.10, The NSPSO shall include in its Market Procedure the minimum notice periods by which NSPI Customer Operations in respect of the Transmission System and Generation Market Participants are required to endeavour to submit Outage Plans in respect of different classes of outage that have not been included in the annual Outage planning cycle.

3.5.3.11, The NSPSO shall endeavour to provide advanced approval of Outage Plans, recognising that this is not always possible in view of uncertainties with respect to load forecast, system conditions, or other Outages.

3.5.3.12, The NSPSO shall make its final determination of Outage Plan approval or rejection following its first issue in accordance with paragraph 4.2.1.3 of a forecast covering the first full day of the planned Outage and shall advise NSPI Customer Operations in respect of the Transmission System and each affected Generation Market Participant accordingly.

Deleted: 30th September, 2006

3.5.3.13, The NSPSO may in an emergency, in order to avoid an emergency, or in order to preserve Reliability of the Bulk Electricity Supply System or any Zone thereof, retract approval of an approved Outage Plan.

3.5.4, Outage commencement, recall and completion

3.5.4.1, The approval of an Outage Plan does not constitute final approval to commence the Outage.

3.5.4.2, NSPI Customer Operations in respect of the Transmission System shall request approval of Outage commencement no more than 2 Business Days, and no less than 6 hours, before the planned commencement of the Outage.

3.5.4.3, Generation Market Participants in respect of their Generating Facilities shall request approval of Outage commencement and of any associated De-synchronization of the Facility no more than 2 Business Days and no less than 6 hours before the planned commencement of the Outage.

3.5.4.4, The NSPSO shall approve Outage commencement unless this would jeopardise the Reliability of the Bulk Electricity Supply System or any Zone thereof, in which case it may either reject the Outage or in consultation with the relevant parties, defer the commencement.

3.5.4.5, The NSPSO may in an emergency, in order to avoid an emergency, or in order to preserve Reliability of the Bulk Electricity Supply System or any Zone thereof, to the extent practical recall equipment from an Outage.

3.5.4.6, NSPI Customer Operations in respect of the Transmission System or the Generation Market Participant for the Generating Facility shall use all reasonable efforts to comply with such recall instructions and to restore the specified equipment or Generating Facility to service.

3.5.4.7, NSPI Customer Operations in respect of the Transmission System and the Generation Market Participant for a Generating Facility shall use all reasonable efforts to compete planned Outages in accordance with the approved Outage Plan and to return the specified equipment or Generating Facility to service by the dates specified in such plan.

Deleted: 30th September, 2006

3.5.4.8, In the event that NSPI Customer Operations in respect of the Transmission System and the Generation Market Participant for a Generating Facility identifies that notwithstanding all reasonable efforts to compete planned Outages in accordance with the approved Outage Plan and to return the specified equipment or Generating Facility to service by the dates specified in such plan, NSPI or the Generation Market Participant expects that completion of the Outage in accordance with such approved Outage Plan is at material risk, it shall notify the NSPSO and may seek approval of an extension of the Outage.

3.5.5, Coming into effect – transition provisions

Deleted: 5

3.5.5.1, The NSPSO shall, within one month of the effective date of these Market Rules, undertake an expedited review of existing Outage Plans with NSPI Customer Operations in respect of the Transmission System and Generation Market Participants in respect of their Generating Facilities in order to reconcile and if necessary facilitate the adjustment of such Outage Plans and approve or reject such Outage Plans. Such expedited review and the associated approval or rejection shall take the place of the annual Outage planning process described in paragraph 3.5.3.6.

3.5.5.2, The NSPSO may, notwithstanding sub-section 3.5.3, issue an interim Market Procedure which may be incomplete with respect to the requirements set out in subsection 3.5.3, but which shall as a minimum provide to Generation Market Participants the information required for their submission of Outage Plans.

3.6, Emergency and system restoration planning and execution

3.6.1, Designation of Emergency Planning Participants

3.6.1.1, The NSPSO shall from time to time identify which Market Participants other than divisions of NSPI are required to participate in planning for response to electricity system emergencies and for electricity system restoration in order to mitigate damage and optimise restoration of the Bulk Electricity Supply System.

Deleted: 30th September, 2006

3.6.1.2, The NSPSO shall designate such Market Participants as Emergency Planning Participants, shall advise each such Emergency Planning Participant, and shall maintain a list of such Emergency Planning Participants.

3.6.2, Preparation of Plans

3.6.2.1, Each Emergency Planning Participant shall prepare and maintain a Participant Emergency Plan which shall:

a) define the levels of authority of responsible personnel of the Emergency Planning Participant in the event of a declared electricity system emergency or of a complete or partial system blackout;

b) set out the means by which NSPI or other responsible persons may communicate with the responsible personnel of the Emergency Planning Participant;

c) set out the actions to be taken immediately by responsible personnel in the event of a declared electricity system emergency or of a complete or partial system blackout;

d) set out the key NSPI or other contact persons and channels of communication to be used in such circumstances, and describe the authority of such contract persons, recognising the provisions in the Standards of Conduct associated with the Transmission Tariff which permit suspension of those Standards of Conduct in declared electricity system emergencies;

e) set out any standard procedures to be implemented by responsible persons in the event of a declared electricity system emergency or of a complete or partial system blackout;

Deleted: 30th September, 2006

f) recognise the role of the Nova Scotia Emergency Measures Organisation in the event of an emergency declared in accordance with the *Emergency Measures Act*, SNS 1990, c.8.

3.6.2.2, Each Participant Emergency Plan shall address electricity system emergencies and electricity system restoration and may also be part of a plan that addresses other declared emergencies.

3.6.2.3, Each Emergency Planning Participant shall submit its draft Participant Emergency Plan to the NSPSO for review, and shall modify its Participant Emergency Plan to fulfil the reasonable requirements of the NSPSO.

3.6.2.4, Each Emergency Planning Participant shall maintain its plan up to date, and shall provide every update to the NSPSO.

3.6.2.5, The NSPSO shall provide to each Emergency Planning Participant the relevant information from, or the relevant portions of, the NSPI emergency and restoration plan.

3.6.2.6, The NSPSO shall disseminate Participant Emergency Plan information within NSPI as appropriate.

3.6.2.7, The NSPSO may specify confidentiality provisions concerning emergency planning information.

3.6.3, Training and systems

3.6.3.1, Each Emergency Planning Participant shall train all responsible personnel and shall maintain all communication and other systems required to support execution of its Participant Emergency Plan in good working condition.

3.6.3.2, The NSPSO shall coordinate the participation of Emergency Planning Participants in coordinated training exercises.

3.6.3.3, The NSPSO may review and audit an Emergency Planning Participant's training and preparedness.

Deleted: 30th September, 2006

3.6.4, Declaration of an emergency and execution of plans

3.6.4.1, The NSPSO may declare an electricity system emergency in accordance with its authority under sub-section 4.9.1 and may or may not suspend its Standards of Conduct in general or in particular.

3.6.4.2, In the event of any such declared electricity system emergency or a system blackout, the provisions of Participant Emergency Plans take precedence over Market Rules only to the extent required for execution of those Participant Emergency Plans.

3.7, Publication and Confidentiality

3.7.1, Confidential Information

3.7.1.1, Confidential Information in respect of Reliability and planning generally includes:

a) Market Participant and Connection Applicant information provided for NSPSO forecasts and assessments;

b) Market Participant Outage Plans for Generating Facilities;

c) Participant Emergency Plans (subject to special provisions as defined by the NSPSO).

3.7.2, Publication

3.7.2.1, The NSPSO shall Publish the following information in respect of Reliability and planning:

a) technical and other standards;

b) system forecasts, assessments and plans;

c) aggregate forecast information with respect to long term import and export contracts considered in the forecasts and assessments, including information aggregated by type of contract;

Deleted: 30th September, 2006

d) Outage planning calendar;

e) aggregated Outage planning information; and

f) any electricity system emergency planning information that is required to be published for emergency preparedness.

Deleted:

Deleted: *30th September, 2006¶*

4, Wholesale and Renewable to Retail Market Operations

4.0, Description

This chapter sets out the rules relating to the Day Ahead and real time operation of the system. These rules apply to the NSPSO and to Market Participants who are responsible for Generating Facilities registered in the market, who are scheduling energy or Ancillary Service transactions over the Transmission System, or who are providing Ancillary Services to the NSPSO.

4.1, Scheduling and dispatch objectives

4.1.1.1, The NSPSO shall, in scheduling and dispatching energy transactions and Ancillary Services, pursue the following objectives in descending order of priority:

a) maintain safety and the Reliability of the Bulk Electricity Supply System in accordance with the requirements of the General Reliability Standards;

b) undertake congestion management of interconnection transactions in accordance with the interconnection agreement between NSPI and the NBSO;

c) complete firm energy transactions and unit-contingent firm energy transactions scheduled by Market Participants;

d) minimise Control Actions except those that only impact non-firm energy transactions energy transactions other than those scheduled by Market Participants or as Ancillary Services, such as purchasing emergency energy and inadvertent exchange;

e) complete non-firm energy transactions scheduled by Market Participants;

Deleted:

Deleted: *30th September, 2006¶*

f) in instances when the NSPSO is required to Re-dispatch resources in order to fulfil the above objectives, the NSPSO shall make the most economical use of the resources available for such Re-dispatch, based on the information provided by Market Participants.

4.1.1.2, In pursuing the above objectives, the NSPSO shall have regard for the capabilities of the Transmission System and of each Facility.

4.2, Information

4.2.1, Daily forecasts

4.2.1.1, The NSPSO may set out in a Market Procedure the information required from Market Participants for the NSPSO's preparation of its daily forecast, and the time by which such information shall be submitted.

4.2.1.2, Market Participants shall provide in a timely manner all information thus specified in a Market Procedure.

4.2.1.3, The NSPSO shall Publish by 10:00 each Business Day its forecast of the net system daily peak demand for each of the following five Dispatch Days.

4.2.2, System status

4.2.2.1, Market Participants may access certain Transmission System status information and messages on the NSPI OASIS.

4.3, Submission of energy schedules

4.3.1, Transmission Customer responsibilities for Bundled Service, Unbundled Service, and Partially Unbundled Service

4.3.1.1, NSPI PP is the Transmission Customer in respect of all Bundled Service and in respect of the bundled portion of Partially Unbundled Service.

4.3.1.2, The Load Market Participant for a Facility taking Unbundled Service or Partially Unbundled Service may be the Transmission Customer for the delivery of the

Deleted:

Deleted: *30th September, 2006¶*

Unbundled Service or the unbundled portion of Partially Unbundled Service, or may designate another Market Participant as the Transmission Customer

4.3.1.3, In executing or amending a service agreement for Network Integration Transmission Service in accordance with the Transmission Tariff, the Transmission Customer for the unbundled portion of Partial Unbundled Service shall designate either:

a) that the unbundled portion is the primary service (as described in paragraph 4.3.1.4); or

b) that the bundled portion is the primary service (as described in paragraph 4.3.1.4).

4.3.1.4, In either case all energy flows and demands up to the MW values scheduled for whichever is the primary service in accordance with section 4.3 shall be attributed to the primary service, and all amounts in excess thereof shall be attributed to the secondary service.

4.3.2, Schedules for Bundled Service, including the bundled portion of Partially Unbundled Service

4.3.2.1, NSPI PP shall submit a single schedule in respect of all Bundled Service, including the bundled portion of Partially Unbundled Service.

4.3.2.2, Each such schedule shall identify in respect of each hour:

a) withdrawals:

i) for individual consumers over 25 MW peak gross demand, the individual withdrawal net of the output of any Load Displacement Generating Facilities, and

ii) for all other customers, the aggregated balance of system wide total withdrawal, net of the output of Load Displacement Generating Facilities; and

b) injections:

i) import transactions, and

Deleted:

Deleted: 30th September, 2006¶

ii) individual Generating Facility injections recognising the requirements or permissions of the NSPSO in accordance with paragraphs 2.2.1.5 and 2.2.1.6 and including any net injections from Facilities aggregated in accordance with paragraph 2.2.1.7, but excluding the output from Load Displacement Generating Facilities.

4.3.2.3, Bundled Service schedules shall exclude exports.

4.3.2.4, The Bundled Service schedule in respect of any Generating Facility shall not exceed the capability of that Generating Facility minus any provision for Ancillary Services to be provided from that Generating Facility, and minus any export or Unbundled Service to be scheduled from that Generating Facility.

4.3.3, Schedules for Unbundled Service, including the unbundled portion of Partially Unbundled Service

4.3.3.1, Each Transmission Customer shall submit a schedule in respect of Unbundled Service, including the unbundled portion of Partially Unbundled Service.

4.3.3.2, A Transmission Customer for more than one Load Market Participant shall submit no more than one schedule in respect of each such Load Market Participant in any hour, and may chose to consolidate schedules for service to more than one such Load Market Participant, subject to; each such schedule shall identify in respect of each hour:

a) withdrawals:

i) individual net withdrawal for each Load Market Participant and Point of Delivery net of the output of any Load Displacement Generating Facilities; and

b) injections:

i) import transactions, and

ii) individual Generating Facility injections recognising the requirements or permissions of the NSPSO in accordance with paragraphs 2.2.1.5 and 2.2.1.6 and including any net injections from

Deleted:

Deleted: *30th September, 2006*¶

Facilities aggregated in accordance with paragraph 2.2.1.7, but excluding the output from Load Displacement Generating Facilities.

4.3.4, Imports and exports

4.3.4.1, Import schedules may be integrated with either Bundled Service or Unbundled Service schedules as appropriate and as noted above.

4.3.4.2, Export transactions shall be scheduled as Point to Point transactions separately from imports and service to Nova Scotia loads.

4.3.4.3, Multiple export transactions may be consolidated into a single schedule reflecting a single nominal Point of Receipt for export service, and identifying the amount of supply from individual Generating Facilities.

4.3.4.4, All import and export schedules are subject to NERC e-tagging requirements.

4.3.4.5, Licenced Retail Supplier Market Participants do not qualify for Import and Export transactions.

4.3.5, Classes of import and export schedules

4.3.5.1, The Market Participant scheduling an import shall designate its class with respect to firmness of energy:

a) Firm imports are subject to curtailment only in accordance with the interconnection agreement between NSPI and the NBSO as a result of inter-tie constraint, general New Brunswick system shortfall or impactive Transmission Loading Relief.

b) Unit-contingent imports are also subject to curtailment in the event of a shortfall in the output of the generating facility designated as the source

c) Other recallable provisions to be specified and subject to acceptance by the NSPSO.

Deleted:

Deleted: 30th September, 2006¶

4.3.5.2, The Market Participant scheduling an export shall designate its class with respect to firmness of energy:

a) Firm exports are subject to curtailment only in accordance with the interconnection agreement between NSPI and the NBSO as a result of inter-tie constraint, general Nova Scotia system shortfall or impactive Transmission Loading Relief.

b) Unit-contingent exports are also subject to curtailment in the event of a shortfall in the output of the Generating Facility designated as the source.

c) Other recallable provisions to be specified and subject to acceptance by the NSPSO.

4.3.5.3, The rules relating to schedules for an import or export of an Ancillary Service are set out in subsection 4.5.4.

4.3.6, Submission of Energy Schedules for the Renewable to Retail Market

4.3.6.1, The Licenced Retail Supplier Market Participant is the Transmission Customer in respect of their aggregate Renewable to Retail generation resources.

4.3.6.2, The Licenced Retail Supplier as the Transmission Customer shall submit a schedule in respect of its aggregate generation resource injections.

4.3.6.3, A Licenced Retail Supplier as the Transmission Customer shall submit no more than one schedule in respect of that Licenced Retail Supplier's Generating Facility(ies) (whether owned or contracted) in any hour; such schedule shall identify in respect of each hour:

a) injections:

the aggregate of all individual Generating Facility injections (whether owned or contracted) recognising the requirements or permissions of the NSPSO in accordance with paragraphs 2.2.1.5 and 2.2.1.6.

4.3.6.4 The Licenced Retail Supplier as the Transmission Customer is not required to provide hourly schedules of its aggregate net withdrawals related to supply of

Deleted:

Deleted: 30th September, 2006¶

its Renewable to Retail customer load. Such withdrawals are included in the NSPI PP hourly system load schedule.

4.3.7, Loss factors

Deleted: 6

NSPI PP Bundled Service scheduling

4.3.7.1, NSPI PP shall in scheduling its Generating Facilities and import transactions for Bundled Service take account of its best estimates of actual energy losses in transmission, including the application of any Special Locational Loss Factor.

Deleted: 6

Unbundled Network Integration Transmission Service scheduling

4.3.7.2, Any Market Participant submitting a schedule for unbundled Network Integration Transmission Service shall take account of the system average loss factor published by the NSPSO for this purpose, and of any Special Locational Loss Factors applicable in respect of Generating Facilities.

Deleted: 6

Point to Point Transmission Service scheduling

4.3.7.3, Any Market Participant submitting a schedule for Point to Point Transmission Service shall take account of the path-specific loss factor published by the NSPSO for this purpose, and of any Special Locational Loss Factors applicable in respect of Generating Facilities.

Deleted: 6

4.3.8, Day Ahead scheduling

Deleted: 7

4.3.8.1, NSPI PP and any other Market Participant scheduling energy under Network Integration Transmission Service (including for Bundled Service) shall submit a complete schedule for each Dispatch Day no earlier than 07:00 and no later than 11:00 on the Day Ahead.

Deleted: 7

4.3.8.2, NSPI PP and any other Market Participant wishing to schedule energy under firm Point to Point Transmission Service are required by the Transmission Tariff to submit such a schedule for each Dispatch Day by 11:00 on the Day Ahead.

Deleted: 7

4.3.8.3, NSPI PP and any other Market Participant wishing to schedule energy under non-firm Point to Point Transmission Service are permitted by the Transmission

Deleted: 7

Deleted:

Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules
Chapter 4, Wholesale and Renewable to Retail Market Operations

Deleted: *30th September, 2006*¶

Tariff to submit such a schedule for each Dispatch Day by 11:00 on the Day Ahead, and are requested but not required so to do.

4.3.8.4, NSPSO shall review those schedules that are submitted by 11:00 on the Day Ahead, and shall by 12:00 notify the Market Participant of any identified problems and of any changes required for purposes of system security.

Deleted: 7

4.3.8.5, Any Market Participant receiving such notification shall address the identified problems and any required changes for purposes of system security and shall by 13:00 submit a revised complete schedule.

Deleted: 7

4.3.8.6, Following review and internal approval of such schedules, the NSPSO is required to provide the schedules to the Reliability Coordinator as required for security coordination.

Deleted: 7

4.3.8.7, In the event that the Reliability Coordinator identifies security concerns with such schedules to the NSPSO, the NSPSO shall advise the relevant Market Participants of such problems, and the Market Participant shall promptly address those problems and submit such schedule revisions as may be required.

Deleted: 7

4.3.8.8, Any rescheduling of Generating Facility output required and carried out in accordance with paragraphs 4.3.8.4 to 4.3.8.7 shall, unless associated with Point to Point Service, be considered as Re-dispatch for purposes of settlement in accordance with paragraph 5.4.1.1.

Deleted: 7

Deleted: 7

Deleted: 7

4.3.9, Additional schedules and updates

Deleted: 8

4.3.9.1, Any Market Participant may submit additional or updated schedules between the times prescribed in sub-section 4.3.8 and sub-section 4.3.10.

Deleted: 8

Deleted: 7

Deleted: 9

4.3.10, Dispatch Day scheduling

Deleted: 9

4.3.10.1, NSPI PP shall before the start of each hour submit an update to the schedule for Bundled Service (including the aggregate net withdrawals related to supply of all Renewable to Retail customer load) that:

Deleted: 9

a) confirms the last previously submitted schedule for the hour about to start (hour 1) except in the event that the NSPSO has directed a change as a result of Control Actions or in response to a Forced Outage or other activation of operating reserve;

b) confirms the last previously submitted schedule for the next hour (hour 2) unless unforeseen circumstances have caused the need for change; and

c) updates without restriction the last previously submitted schedule for the next two hours (hours 3 and 4).

4.3.10.2, NSPI PP, except in respect of the schedule for Bundled Service, and other Market Participants may in accordance with the tariff submit new or revised schedules in respect of any hour until 30 minutes before the start of that hour, but are requested to make such submissions no later than 60 minutes before the start of the hour in order to facilitate and provide better assurance of checkout of any import or export transactions.

4.3.10.3, NSPSO shall promptly notify any Market Participant whose schedule is not accepted or which fails checkout in respect of import or export.

4.3.11, Late changes

4.3.11.1, Schedule changes after the times prescribed in sub-section 4.3.10 are not permitted except in the event that the NSPSO has directed a change as a result of Control Actions or in response to a Forced Outage or other activation of Operating Reserve, or except in the event that the NSPSO grants special authorisation.

4.4, Intermittent Generating Facility operations

4.4.1.1, The Market Participant for an Intermittent Generating Facility shall submit and update schedules in respect of such Facility operation in accordance with section 4.3.

Deleted:
Deleted: *30[th] September, 2006¶*
Deleted: Operating
Deleted: Reserve
Deleted: 9
Deleted: 9
Deleted: 0
Deleted: 10
Deleted: 9

Deleted:

Deleted: *30th September, 2006¶*

4.4.1.2, In submitting such schedules, the Market Participant shall undertake commercially reasonable efforts to forecast the hourly output of such Facilities, in accordance with a protocol to be established by agreement with the NSPSO recognising that:

a) the need for forecast accuracy depends on the size of the Intermittent Generating Facility; and

b) the need for forecast accuracy may vary according to the location of the Facility connection and the condition of the Transmission System. Accuracy is particularly critical if transmission constraints would require the re-dispatch of other Generating Facilities to accommodate the output of an Intermittent Generating Facility.

4.4.1.3, Subject to the approval of the NSPSO, the protocol for scheduling output of a particular Intermittent Generating Facility may reflect its aggregation in accordance with paragraph 2.2.1.6 with other Generating Facilities, including with other Intermittent Generating Facilities, and if applicable its aggregation in accordance with paragraph 2.2.1.7.

4.4.1.4, Subject to the approval of the NSPSO, the protocol for scheduling output of a particular Intermittent Generating Facility may provide for a Wholesale Customer to utilise Generator Balancing Service by others as permitted under the Transmission Tariff.

Deleted:

Deleted: Market Participant

4.5, Ancillary Service scheduling

4.5.1, Energy imbalance service

4.5.1.1, The NSPSO may re-dispatch any available Dispatchable Generating Facility in accordance with section 4.8 in order to provide energy imbalance service.

4.5.2, Reactive Power and Voltage Support

4.5.2.1, The NSPSO shall determine the reactive power or voltage set-points for all Generating Facilities with reactive power or voltage control capability, taking

Deleted:

Deleted: 30th September, 2006¶

account of scheduled and actual grid conditions. In determining the set-points of each generating facility the NSPSO shall:

a) give primacy to the security of the grid;

b) within any region of the grid, generally and over time allocate reactive power service obligations on a non-discriminatory basis in proportion to the Facility Reactive Power Capability of each Generating Facility; and

c) seek to minimise control adjustments.

4.5.2.2, The NSPSO may provide an initial schedule of VAR requirements to Market Participants in advance, or may provide directions for immediate implementation at any time.

4.5.2.3, Market Participants for Generating Facilities shall promptly adjust the dispatch of their Facilities to comply with the direction of the NSPSO, and shall promptly notify the NSPSO of any inability to comply or any delay in compliance.

4.5.3, Other Nova Scotia Ancillary Services

4.5.3.1, In accordance with the provisions of the Transmission Tariff, Transmission Customers may self-supply Ancillary Services otherwise covered by schedules 3, 4, 5 and 6 of the Transmission Tariff.

4.5.3.2, Any Market Participant that is providing self-supplied Ancillary Services shall submit its schedule for the provision of such self-supplied Ancillary Services, and shall update such schedules, at the same times as it submits its energy schedules as set out in section 4.3.

4.5.3.3, NSPI PP is the sole provider to the NSPSO of Ancillary Services from generation other than those that are self-supplied by Transmission Customers.

4.5.3.4, NSPI PP shall submit its schedule for the provision of such Ancillary Services, and shall update such schedules, at the same times as it submits its Bundled Service schedules as set out in section 4.3.

Deleted:

Deleted: *30th September, 2006¶*

4.5.4, Ancillary Service import and export schedules

4.5.4.1, The self-supply of certain Ancillary Services in accordance with paragraph 4.5.3.2 may, subject to activation arrangements satisfactory to the NSPSO include import of such Ancillary Service.

4.5.4.2, The supply by NSPI PP of certain Ancillary Services in accordance with paragraph 4.5.3.4 may, subject to activation arrangements satisfactory to the NSPSO include import of such Ancillary Service.

4.5.4.3, A Transmission Customer may subject to paragraph 4.5.4.4 and to the provisions applicable to export schedules for energy submit an export schedule for Ancillary Services.

4.5.4.4, A Transmission Customer may only submit an export schedule for an Ancillary Service if the Transmission Customer has secured prior approval from the NSPSO of the process for communicating activation of the Ancillary Service and for adjustment to energy schedules to reflect such activation.

4.6, Data setting out estimated marginal costs, energy limits, and environmental restrictions

4.6.1.1, Each Market Participant for a Dispatchable Generating Facility shall submit marginal cost estimates for use by the NSPSO in Re-dispatch of such Dispatchable Generating Facilities.

4.6.1.2, Each Market Participant for a Generating Facility that is subject to a limit on the total energy production in a given Dispatch Day shall submit to the NSPSO details of such limit.

4.6.1.3, Each Market Participant for a Generating Facility that is subject to firm environmental restrictions on its operations in a given Dispatch Day shall submit to the NSPSO details of such restrictions.

4.6.1.4, Market Participants shall make the submissions identified in this section no later than the first submission of the schedule to which they relate.

Deleted:

Deleted: *30th September, 2006¶*

4.6.1.5, The NSPSO shall issue a Market Procedure setting out the form, content and other details of the submissions required in accordance with this sub-section.

4.7, Synchronization and De-synchronization

4.7.1.1, The Market Participant for a Generating Facility other than a Minor Generating Facility may not Synchronize or De-synchronize such Generating Facility or any unit thereof without prior authorization of the NSPSO except in the event of a Forced Outage.

4.7.1.2, The Market Participant for a Generating Facility shall make all reasonable efforts to request authorization to Synchronize or to De-synchronize with at least one hour's notice.

4.7.1.3, The NSPSO shall respond within one hour of a Market Participant's request to Synchronize or De-synchronize.

4.7.1.4, The NSPSO may direct or authorise Synchronization or De-synchronization of a Generating Facility or unit thereof at such shorter notice as may be required for Reliability of the Bulk Electricity Supply System.

4.8, Real time operation and Re-dispatch

4.8.1, Market Participant obligations

4.8.1.1, The Market Participant for a Dispatchable Generating Facility or for a non-Dispatchable Export Generating Facility shall either establish a protocol with the agreement of the NSPSO for ramping the Generating Facility between its scheduled output levels in successive hours, or shall secure approval each hour for such ramping.

4.8.1.2, The Market Participant for a Dispatchable Generating Facility or for a non-Dispatchable Export Generating Facility shall make all reasonable efforts to operate the Generating Facility in accordance with approved schedules or subsequent Re-dispatch instructions from the NSPSO, recognising the ramping

Deleted:

Deleted: *30th September, 2006¶*

provisions of paragraph 4.8.1.1, and particularly to operate the Facility so as not to deviate therefrom by more than the control dead-band established as part of the Facility registration process.

4.8.1.3, The Market Participant for a Generating Facility including an Intermittent Generating Facility shall make all reasonable efforts to operate the Generating Facility exactly in accordance with and with the reactive power or voltage control directions of the NSPSO.

4.8.1.4, The Market Participant for a Generating Facility shall immediately advise the NSPSO of any unforeseen event that limits or is expected to limit the capability of the Generating Facility to provide energy or Ancillary Services (whether scheduled or not), or that impairs the operation of protection or communications systems. Any such event shall be designated as a Forced Outage, and shall be subject to the reporting provisions of sub-section 4.8.5.

4.8.1.5, To the extent reasonable practical, the Market Participant for a Generating Facility subject to a Forced Outage shall not remove the Generating Facility from service until after it has advised the NSPSO of the Forced Outage event and any requirement to remove the Generating Facility from service.

4.8.1.6, The NSPSO may request that the Market Participant retain the Generating Facility in service for sufficient time, recognising what is reasonably practical in the circumstances, to mitigate impact on the Bulk Electricity Supply System.

4.8.1.7, The Market Participant shall reasonable consider any such request and, subject to overriding considerations of safety and prevention of damage, shall seek to comply with such request.

4.8.2, NSPSO Re-dispatch instructions

Reasons for Re-dispatch

4.8.2.1, In the event that:

a) the actual system load varies from the forecast reflected in schedules;

Deleted:

Deleted: *30th September, 2006¶*

b) a transmission constraint precludes the implementation of schedules as submitted;

c) voltage support or reactive power requirements require Re-dispatch;

d) a Generating Facility suffers a Forced Outage or otherwise fails to fulfill its schedule;

e) the actual output of Intermittent Generating Facilities varies from the scheduled output;

f) the NSPSO needs to correct accumulated inadvertent energy flows on the interconnection with New Brunswick; or

g) the New Brunswick System Operator initiates activation of Operating Reserve, or requests emergency support, in accordance with the interconnection agreement between NSPI and the New Brunswick System Operator;

the NSPSO may Re-dispatch one or more Dispatchable Generating Facilities as required.

Selection of Generating Facilities for Re-dispatch

4.8.2.2, The NSPSO shall select Generating Facilities for Re-dispatch taking account of:

a) the capability of the Generating Facility to serve the requirement (particularly with respect to transmission constraints and voltage control / reactive power);

b) ramping capability (particularly in the activation of Operating Reserve in response to a contingency event);

c) election by the Market Participant for any Generating Facility to be preferentially constrained-off in the event of particular transmission constraints; and

d) the most economic fulfillment of the need, based on the marginal cost estimates provided by Market Participants and any energy limits and

Deleted:

Deleted: 30th September, 2006¶

environmental restrictions advised by Market Participants, and taking account of marginal locational loss factors if relevant.

4.8.2.3, In the event that the Re-dispatch of Dispatchable Generation Facilities will not completely resolve the event identified in paragraph 4.8.2.1, then the NSPSO may issue a Re-dispatch instruction to a Market Participant for the reduction of the output of an Intermittent Generating Facility In the event of a need to Re-dispatch Intermittent Generating Facilities, the NSPSO shall do so on a non-discriminatory basis, having regard for any environmental considerations and, in the event that a single Market Participant is responsible for more than one impacted Intermittent Generating Facility, the preferences of that Market Participant with respect to those Facilities.

Issue of Re-dispatch instructions

4.8.2.4, The NSPSO shall issue Re-dispatch instructions to the person so designated by each Market Participant.

4.8.3, NSPSO operation of Generating Facilities

4.8.3.1, A Market Participant may with the agreement of the NSPSO assign to the NSPSO the direct control of certain Generating Facilities.

4.8.3.2, The NSPSO shall use all reasonable efforts to operate such Generating Facilities in accordance with the schedule provided by the Market Participant, subject to Re-dispatch in accordance with sub-section 4.8.2.

4.8.3.3, If the NSPSO operator initiates any deviation from schedule in respect of such Generating Facilities, it shall be considered as an instructed Re-dispatch.

4.8.4, Regulation service

4.8.4.1, The NSPSO shall have the ability for direct and automatic control of Generating Facilities providing regulation and frequency response service.

Deleted:

Deleted: *30th September, 2006¶*

4.8.5, Forced Outage reporting

4.8.5.1, The Market Participant for any Generating Facility, other than a Load Displacement Generating Facility, that suffers a Forced Outage shall within two Business Days of the start of such Forced Outage submit a report in a form acceptable to the NSPSO describing the Forced Outage, its cause, and any remedial actions undertaken or planned.

4.8.5.2, To the extent that the information is incomplete at that time, the Market Participant shall make a complete report promptly on the information becoming available.

4.8.5.3, The NSPSO may require sufficient additional information to determine nature of the Forced Outage, the root and proximate causes, and the appropriate remedial actions, and may request such information from the Market Participant, from NSPI Customer Operations and any other Market Participant who may have relevant information.

4.8.5.4, NSPI Customer Operations or the Market Participant receiving any such request shall promptly provide such additional information, as well as subsequent confirmation of the completion of any remedial actions.

4.8.5.5, The NSPSO shall advise the Market Participant of any findings it makes with respect to the cause of a Forced Outage.

4.9, Control Actions and special operating states

4.9.1, NSPSO responsibilities and authority

4.9.1.1, The NSPSO is responsible to preserve the security of the Nova Scotia Transmission System and to take actions determined by the Reliability Coordinator for the preservation of security of the transmission system in the Maritime region.

4.9.1.2, The NSPSO is responsible, subject to paragraph 4.9.1.1, to undertake congestion management of interconnection transactions in accordance with the interconnection agreement between NSPI and the NBSO.

Deleted:

Deleted: 30th September, 2006¶

4.9.1.3, In order to complete its responsibilities under paragraphs 4.9.1.1 and 4.9.1.2, and to minimise disruption of firm energy transactions and unit-contingent firm energy transactions scheduled by Market Participants the NSPSO has the authority to take Control Actions including:

a) interruption of transactions utilising non-firm transmission service;

b) operation of the system in accordance with emergency or high risk operating state limits or with reduced operating or supplementary reserves;

c) mobilisation of all available generation resources, including requests that Market Participants seek temporary waiver of environmental restrictions on Generating Facility operations;

d) recall of transmission equipment and Generating Facilities from Outages, where practical;

e) interruption of all non-firm load;

f) interruption of firm exports;

g) load reduction through 5% voltage cuts;

h) declaration of an electrical system emergency operating state and purchase of emergency energy; and

i) interruption of firm load.

4.9.1.4, Subject to the applicable provisions of the interconnection agreement between NSPI and the NBSO, the sequencing of Control Actions is a matter for the NSPSO operating personnel operating in accordance with guidelines established by the NSPSO and taking account of the circumstances as they arise.

4.9.1.5, The NSPSO shall seek to give reasonable notice of conditions that may lead to the use of Control Actions and of the invocation of particular Control Actions, recognising that circumstances may limit or preclude notice.

Deleted:

Deleted: *30th September, 2006¶*

4.9.1.6, When issuing any directive to a Market Participant for implementation of a Control Action, the NSPSO shall identify this as a Control Action requirement either:

a) by a prior general notice of an actual or expected emergency operating state;

b) in any prior notice of the expected Control Action requirement; or

c) in issuing the directive to the Market Participant.

4.9.1.7, The NSPSO shall initiate interruption of all supply designated as economically interruptible in advance of, and in every case no later than, initiating any Control Action.

4.9.2, Market Participant obligations

4.9.2.1, A Market Participant receiving a directive for a Control Action shall use all efforts to comply, and shall immediately advise the NSPSO of any actual or expected delay or problems in compliance.

4.10, Confidential Information and Publication

4.10.1, Confidential Information

4.10.1.1, Confidential information includes the following categories of information:

a) Generating Facility and Load Facility operating status and current capability;

b) Generating Facility and Load Facility environmental data not otherwise in the public domain;

c) Generating Facility and Load Facility operating plans;

d) schedules for energy transactions and the provision of Ancillary Services;

e) estimated and actual cost data;

Deleted:

Deleted: *30th September, 2006¶*

f) re-dispatch instructions;

g) Forced Outage reports;

f) communications relating to the above matters; and

i) Facility data except as listed in paragraph 4.10.2.1.

4.10.2, Publication

4.10.2.1, The NSPSO shall Publish:

a) Transmission System data:

   i) system data, and

   ii) emergency or high risk states, beginning and end:

b) forecast data:

   i) short term forecasts as set out in section 4.2.1:

c) current (10 minute average) estimated data:

   i) total net Nova Scotia load,

   ii) net energy flow to / from New Brunswick:,

   iii) net energy flow “Cape Breton Export”, and

   iv) net energy flow “Onslow South”;

d) historic data, to be published within 10 business days of the end of each month:

   i) hourly total net Nova Scotia load,

   ii) hourly net energy flows to / from New Brunswick, Cape Breton Export, and Onslow South, and

   iii) hourly New Brunswick intertie TTC & ATC; and

e) historic data, to be published within 2 months of the end of each year:

   i) monthly Generating Facility energy output, and

Deleted:

Deleted: *30th September, 2006¶*

ii) annual Generating Facility reliability and availability data in the form and detail requiring to be filed with NERC or NPCC.

Deleted: 30th September, 2006

5, Settlement

5.0, Description

This chapter sets out the rules relating to the settlement arising from market operations. These rules therefore apply to settlement between the NSPSO and Market Participants, and do not apply to settlement between Market Participants and other parties (including other Market Participants) in respect of their bilateral transactions which may be scheduled over the Transmission System by the NSPSO. These rules do not apply to settlement between NSPI and its customers for Bundled Service. The rules for invoicing and payment do not apply to transactions between the NSPSO and other divisions of NSPI; such inter-divisional transactions will be recorded where appropriate as book entries.

5.1, Metering Data Management

5.1.1, Meter reading

5.1.1.1, The NSPSO shall arrange for the collection and management of all metering data required for settlement under the Market Rules, including through the use of the resources of NSPI Customer Service division.

5.1.2, Error correction

5.1.2.1, For all Generating Facilities that are the subject of a Generator Interconnection Agreement, the process for error correction and adjustment shall be as set out in article 7 of that agreement. For all Generating Facilities that are the subject of a Standard Small Generator Interconnection and Operating Agreement the process for error correction and adjustment shall be as set out in article 2.5 of that agreement.

5.1.2.2, For all Load Facilities or Distribution Systems, the process for error correction and adjustment shall be in accordance with Regulation 5.5 of the NSPI Rates and Regulations approved by the Board.

Deleted: 30th September, 2006

5.1.3, Data access

5.1.3.1, Metering data is the confidential property of the NSPSO.

5.1.3.2, Metering data, including meter output data and all error corrections and adjustments, shall be made available in a reasonable and convenient form to the Transmission Provider and to any Market Participant whose settlement under the Transmission Tariff or Market Rules is directly dependent on such metering data.

5.1.4, Metering disputes

5.1.4.1, For all Generating Facilities that are the subject of a Generator Interconnection Agreement, any disputes over metering are subject to resolution in accordance with Section 7 of the transmission Generator Interconnection Agreement or Section 2.5 of the Standard Small Generator Interconnection Agreement as applicable.

5.1.4.2, For all Load Facilities or Distribution Systems, any disputes over metering are subject to resolution in accordance with Regulation 6.7 of the NSPI Rates and Regulations approved by the Board.

5.2 Adjustments

5.2.1, Local loss factors and adjustments

5.2.1.1, All metered energy and demand quantities shall for the purposes of settlement under the Market Rules be adjusted as necessary to reflect the quantities at transmission voltage.

5.2.2, Special Locational Loss Factor

5.2.2.1, In the event that a new or significantly expanded Generating Facility has been assigned a Special Locational Loss Factor in accordance with paragraph 2.2.6.4, the metered output of the Facility shall be further adjusted accordingly.

Deleted: 30th September, 2006

5.3, Settlement – general

5.3.1.1, The NSPSO shall undertake settlement calculations and prepare settlement statements for all Market Participants including NSPI, on a common basis, subject to limitations imposed by the unavailability of revenue-quality metering data at NSPI PP Generating Facility Points of Receipt and at transmission Points of Delivery used only for the supply of Bundled Service.

5.3.1.2, Settlement within NSPI, including transactions between the NSPSO and other parts of NSPI, will not be subject to invoicing and cash payment, but will be recorded as book entries only.

5.4, Energy Re-dispatch

5.4.1, Eligibility for energy Re-dispatch settlement

5.4.1.1, In accordance with paragraph 4.3.7.8 and except as noted in paragraphs 5.4.1.3 to 5.4.1.5, Market Participants for Generating Facilities that are required to adjust their schedule including in the Day Ahead in order to address transmission constraints, except in the case of Point to Point Transmission Service, or voltage support requirements are eligible for energy Re-dispatch settlement.

5.4.1.2, Except as noted in paragraphs 5.4.1.3 to 5.4.1.5, Market Participants for Generating Facilities that are Re-dispatched up or down by the NSPSO relative to their schedule, are eligible for energy Re-dispatch settlement, including in respect of reserve activation initiated by the Reliability Coordinator and the repayment following reserve activation.

5.4.1.3, Market Participants for Generating Facilities that are Re-dispatched down as a result of proportionate reduction of Point-to-Point transmission flows are not eligible for energy Re-dispatch settlement in respect thereof.

5.4.1.4, NSPI PP is not eligible for energy Re-dispatch settlement in respect of Re-dispatch to address energy imbalance.

Deleted: 30th September, 2006

5.4.1.5, NSPI PP is not eligible for energy Re-dispatch settlement in respect of Re-dispatch associated with inadvertent energy flows on the intertie to New Brunswick or the repayment of such inadvertent flows.

5.4.2, Determination of quantity of Re-dispatch eligible for settlement

5.4.2.1, The quantity of eligible Re-dispatch up in any hour, measured in MWh, is the lesser of:

a) the excess of the total MWh output implied by a Re-dispatch instruction over the hour or the relevant portion thereof, over that implied by the Market Participant's schedule; and

b) the excess of the total actual MWh output measured over the hour or the relevant portion thereof, over that implied by the Market Participant's schedule.

5.4.2.2, The quantity of eligible Re-dispatch down in any hour, measured in MWh, is the greater of:

a) the excess of the total MWh output implied by the Market Participant's schedule over that implied by a Re-dispatch instruction, measured over the hour or the relevant portion thereof; and

b) the excess of the total MWh output implied by the Market Participant's schedule over the actual output, measured over the hour or the relevant portion thereof, but not more than 120% of the excess implied by the Re-dispatch instruction.

5.4.3, Determination of settlement amount for Re-dispatch up

5.4.3.1, Following any event of Re-dispatch up, the Market Participant may, at any time prior to the end of the month following the event, submit a claim for Re-dispatch settlement to the NSPSO.

5.4.3.2, Any such claim shall be supported by data setting out the actual variable fuel and operation and maintenance cost per MWh of compliance with the Re-

Deleted: 30th September, 2006

dispatch instruction, which may include reference to previously filed cost information.

5.4.3.3, For the case of a hydraulic Generating Facility for which the Re-dispatch up has an opportunity cost, the Market Participant may make its claim on the basis of such opportunity cost per MWh, together with appropriate supporting data.

5.4.3.4, The rate per MWh of Re-dispatch up shall be the lesser of the appropriate actual or opportunity cost thus established and 120% of the Re-dispatch cost estimate provided to the NSPSO in accordance with section 4.6.

5.4.3.5, The amount payable by the NSPSO to the Market Participant shall be the product of the rate thus established and the quantity established in accordance with paragraph 5.4.2.1.

5.4.4, Determination of settlement amount due for Re-dispatch down

5.4.4.1, Following any event of Re-dispatch down, the NSPSO shall determine the Re-dispatch settlement amount, and shall provide its determination prior to the end of the month following the event.

5.4.4.2, The NSPSO may require the Market Participant to submit data setting out the actual variable fuel and operation and maintenance cost per MWh that the Market Participant has avoided through compliance with the Re-dispatch instruction, which may include reference to previously filed cost information.

5.4.4.3, For the case of a hydraulic Generating Facility for which the Re-dispatch down has an opportunity benefit, the NSPSO may require the Market Participant to provide data with respect to such opportunity benefit per MWh.

5.4.4.4, The NSPSO may require the Market Participant to submit its calculation of the settlement amount in respect of Re-dispatch down.

5.4.4.5, Any Market Participant required by the NSPSO to submit data in accordance with paragraphs 5.4.4.2, 5.4.4.3 or 5.4.4.4 shall do so within 10 business days.

Deleted: 30th September, 2006

5.4.4.6, The NSPSO may rely on previously filed cost information, including that filed under sub-section 5.4.3 above, in its determination of the settlement amount for Re-dispatch down.

5.4.4.7, The rate per MWh of Re-dispatch down shall be the greater of the actual saving or opportunity benefit thus established and 80% of the Re-dispatch cost estimate provided to the NSPSO in accordance with section 4.6.

5.4.4.8, The settlement amount payable by the Market Participant to the NSPSO shall be the product of the rate thus established and the quantity established in accordance with paragraph 5.4.2.2.

5.4.5, NSPSO right to audit data and to make adjustments

5.4.5.1, The NSPSO may request additional supporting data and may review or audit data submitted under this section at any time within a year of the Re-dispatch event to which it applies.

5.4.5.2, The Market Participant shall promptly submit any additional data thus requested, and shall assist the NSPSO in any review or audit.

5.4.5.3, If the NSPSO determines that such additional data, review or audit reveals any Re-dispatch settlement to have been in error, it may following notice to the Market Participant make appropriate settlement adjustments.

5.4,6, Offsets and waivers

5.4.6.1, The NSPSO and a Market Participant may, subject to the following conditions, agree to offset or waive settlement for Re-dispatch:

a) such agreement shall be for no more than one year at a time;

b) such agreement shall generally apply to all transactions between the NSPSO and the Market Participant with respect to one or more categories listed in paragraph 5.4.7.1;

c) such agreement shall not in the judgement of the NSPSO be expected to cause additional cost or harm to any other Market Participant; and

Deleted: 30th September, 2006

d) the NSPSO shall Publish the existence of such agreements, including their duration, scope and Market Participant.

5.4.7, Accounting for Re-dispatch settlement amounts

5.4.7.1, The NSPSO shall allocate all Re-dispatch settlement amounts to:

a) reactive power and voltage control;

b) imbalance; or

c) congestion management.

5.4.7.2, The NSPSO may make such allocation on the basis of its estimates of the causes of Re-dispatch.

5.4.8, Re-dispatch in response to a Control Action directive

5.4.8.1, In the event that a Generation Market Participant other than NSPI PP is subject to Re-dispatch as a Control Action either;

a) in respect of a Dispatchable Generating Facility to a level of output that is not covered by a marginal cost estimate provided in accordance with sub-section 4.6; or

b) in respect of a Generating Facility that is not a Dispatchable Generating Facility;

then that Generation Market Participant shall be eligible for Re-dispatch settlement notwithstanding the lack of an applicable marginal cost estimate.

5.4.9, Market Procedure

5.4.9.1, The NSPSO may issue a Market Procedure setting out the process for submitting Re-dispatch settlement claims and the information that the NSPSO requires.

Deleted: 30th September, 2006

5.5, Ancillary Services procured

5.5.1, Reactive power and voltage support

5.5.1.1, The NSPSO shall pay Generation Market Participants for the variable and opportunity costs of actual provision of reactive power and, for the balance, in proportion to the capability of their Generating Facilities, all as set out below.

Determination of Generating Facility reactive power capability

5.5.1.2, On an annual basis, and otherwise as required as a result of the addition, retirement or modification of a Generating Facility, the NSPSO shall determine the Facility Reactive Power Capability of each registered Generating Facility that provides reactive power under the direction of the NSPSO. The Facility Reactive Power Capability shall be measured in MVAR at transmission voltage and shall be the lesser of:

a) actual reactive power injection capability while generating energy output at its nominal energy capability; and

b) reactive power injection capability requirement at nominal energy capability as determined by the applicable technical standard or any higher standard determined in the System Impact Study to be applicable to that Facility.

Determination of System Reactive Power Capability and Facility Reactive Power Capability Share

5.5.1.3, The System Reactive Power Capability is the total of all the Facility Reactive Power Capabilities.

5.5.1.4, The Facility Reactive Power Capability Share of any Facility in any month is the Facility Reactive Power Capability divided by the System Reactive Power Capability.

Deleted: 30th September, 2006

Determination of the variable and opportunity costs of providing reactive power

5.5.1.5, The variable cost of providing reactive power is limited to:

a) the variable cost of synchronous condenser operation; and

b) the net cost of Re-dispatch of energy in order to address voltage support requirements as determined in accordance with section 5.4.

5.5.1.6, Any requirement by the NSPSO for synchronous condenser operation of a generation facility for the purposes of providing reactive power and voltage support shall be treated as a Re-dispatch up and settled in accordance with section 5.4.

5.5.1.7, The opportunity cost of providing reactive power is limited to circumstances where the NSPSO requires provision of reactive power in excess of the Facility Reactive Power Capability as determined above.

5.5.1.8, To the extent that the provision of reactive power in excess of the Facility Reactive Power Capability results in a net variable cost to the Market Participant, it shall be settled as Re-dispatch down in respect of the reduced energy output in accordance with section 5.4.

Determination of total reactive power revenue and net reactive power revenue

5.5.1.9, The total reactive power revenue in any month is the amount determined in accordance with schedule 2 of the transmission tariff, as applied to all transmission service including that used by NSPI for Bundled Service and other purposes.

5.5.1.10, The net reactive power revenue in any month is the total reactive power revenue less the variable and opportunity costs of providing reactive power as determined in accordance with paragraphs 5.5.1.5 to 5.5.1.8 above for the respective month.

Deleted: 30th September, 2006

Determination of Market Participant reactive power credit

5.5.1.11, The Market Participant Reactive Power Capability Share in any month as the total of the Facility Reactive Power Capability Shares in respect of the Facilities for which it is the Market Participant.

5.5.1.12, The NSPSO shall credit to each Market Participant its Reactive Power Capability Share of the net reactive power revenue for each month.

5.5.2, Energy imbalance procurement

5.5.2.1, NSPI PP fulfills all energy imbalance requirements except those fulfilled by re-dispatch of other Market Participant Generating Facilities.

5.5.2.2, The NSPSO shall therefore credit the full amounts collected for energy imbalance under the transmission tariff to NSPI PP, less the net amount of settlement with other Market Participants in respect of Re-dispatch for purposes of matching energy imbalance.

5.5.3, Other Ancillary Service procurement

5.5.3.1, Certain other Ancillary Services are procured only from NSPI PP, so that the NSPSO shall credit to NSPI PP the full amounts collected under the transmission tariff schedules in respect of :

a) load following;

b) operating reserve; and

c) supplemental reserve.

5.6, Transmission Tariff

5.6.1.1, Charges to Transmission Customers shall be determined and invoiced in accordance with the Transmission Tariff.

Deleted: 30th September, 2006

5.7, Reserved

5.8, Invoicing and financial settlement

5.8.1, Invoice and settlement statement

5.8.1.1, The NSPSO shall invoice each Market Participant for the net amount of charges and credits arising in the respective month.

5.8.1.2, The NSPSO shall make available to each Market Participant, in the invoice or by other agreed means, the calculation of each amount included in the invoice.

5.8.2, Deadlines

5.8.2.1, The NSPSO shall issue its invoices within a reasonable time after the end of the month in which the charges and credits arise.

5.8.2.2, The NSPSO and Market Participants shall make full payment of such invoices no later than the last Business Day not more than 20 days after the date of issue of the invoice. For payments by mail, the payment date shall be the date of the postmark.

5.8.3, Disputes

5.8.3.1, If a Market Participant becomes aware of an error or otherwise disputes an invoice, it shall promptly notify the NSPSO.

5.8.3.2, The NSPSO may if appropriate issue a revised invoice.

5.8.3.3, Disputes that cannot be resolved at the normal staff level shall be subject to the dispute resolution process set out in section 2.8, unless the disputes relate to metering data, in which case the relevant metering data dispute resolution process identified in sub-section 5.1.4 shall apply.

Deleted: 7

Deleted: 30th September, 2006

5.8.3.4, Payment of invoiced amounts is due in full, irrespective of any such notification of error or dispute, and without prejudice to the resolution of such error or dispute.

5.8.3.5, A Market Participant may, following notification to the NSPSO, pay any disputed portion into an independent escrow account pending resolution of the dispute.

5.8.4, Delay and Default

5.8.4.1, Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified in Regulation 5.4 of NSPI Rates and Regulations as approved by the Board.

5.8.4.2, In the event of a Market Participant payment default that has not been remedied within 30 days of notice by the NSPSO, the NSPSO may suspend all or certain of the Market Participant's rights as a Market Participant in accordance with the provisions of section 2.5, and may ultimately Terminate market participation in accordance with that section. Such actions are in addition to, and not in replacement of, rights of recovery and rights under the Transmission Tariff or other agreements.

5.9, Publication and Confidentiality

5.9.1, Confidential Information

5.9.1.1, Settlement information is confidential except as specifically required to be Published.

5.9.2, Publication

5.9.2.1, The NSPSO shall Publish the following information:

a) invoicing dates and payment deadlines;

b) system aggregates of energy and peak monthly demand, based on metering data, and as used in the determination of charges under the Transmission Tariff;

Deleted: *30th September, 2006*

c) information specified in sub-paragraph 5.4.6.1 (d); and

d) the System Reactive Power Capability.

Changes to the

NS Power Regulations

for the Renewable to Retail Application are in these sections:

Section 1.1	Interpretation and Definitions
Section 1.3	Infringement of Regulations
Section 2.2	Agreement
Section 3.6.2	Availability
Section 3.6.3.2	Customer
Section 5.3	Alternate Billing Plans

Regulations

Issued

Deleted: January 1

Deleted: ,

Deleted: 2015

Nova Scotia Power Inc.
Tariffs & Regulations
Approved by the Nova Scotia Utility and Review Board
pursuant to The Public Utilities Act,
R.S.N.S., 189,c.380 as amended

REGULATION

INDEX REGULATION

INDEX REGULATION

1.1 INTERPRETATION AND DEFINITIONS

Interpretation	In these regulations unless the context requires otherwise: Words importing male persons include female persons and corporations. Words importing the singular include the plural and vice versa. Marginal notes and appended citations form no part of these regulations and are deemed to have been inserted for convenience of reference only. In these regulations unless the context requires otherwise:
"Board"	"Board" means the Nova Scotia Utility and Review Board;
"Company"	"Company" means the Nova Scotia Power Incorporated;
"Customer"	"customer" includes a person who is receiving, intends to receive, or has received electrical energy or electric services from the Company. For greater certainty, this includes an RtR Customer receiving Distribution System Access;
"Demand"	"demand" means the maximum kW/kV.A recorded over a specified time period;
"Distribution System Access"	The services provided by the Company under the Distribution Tariff to provide for the connection of the RtR Customer to the Company's distribution system, but does not include the provision of electricity. These services are comprised of delivery of electricity on the distribution system and related services including connections, disconnections, line and service extensions, inspection services, meter services, power restoration, meter reading, and customer service, all in accordance with the applicable Regulations;
"Farming or Fishing Unit"	

Deleted:

Deleted:

1.1 INTERPRETATION AND DEFINITIONS

"farming or fishing unit" means a farming or fishing	business at one location, whether a single or family operation, partnership, or incorporated business;
"Licenced Retail Supplier (LRS)"	A Retail Supplier who: (a) holds a valid Retail Supplier Licence; and (b) has a valid LRS Participation Agreement executed with the Company. For certainty, a Wholesale Customer is not a Licenced Retail Supplier;
"Load"	"load" means power and energy with the power measured in kW/kV.A and the energy in kW.h;
"LRS Participation Agreement"	"LRS Participation Agreement means the agreement (and any amendments or supplements thereto) between a Licenced Retail Supplier and the Company with respect to the sale of renewable low-impact electricity by the LRS in the form approved by the Board;
"Meter"	"meter" means an electric meter, and includes a machine, apparatus or instrument used for making electrical measurements, and any device utilized for the purpose of obtaining the basis of a charge for electricity;

1.1 INTERPRETATION AND DEFINITIONS

"Meter seal"	"meter seal" means either the seal placed on the meter by Industry Canada to prevent fraudulent interference with the passage of electricity through the meter or the seal placed by the Company on the terminal plate or the meter band securing the meter to the base, and includes a seal placed on the demand reset where demand indicating meters are involved and other installations as required;
"Mobile home"	"mobile home" means any portable dwelling having no permanent foundation and supported by wheels, jacks or similar supports, used or so constructed as to permit its being used as a conveyance upon public streets or highways and designed and constructed to permit occupancy for dwelling or sleeping quarters. This does not include travel trailers, tent trailers or trailers otherwise designed;
"Normal business hours"	"normal business hours" means 0830 hrs to 1630 hrs, Monday to Friday inclusive excluding Statutory holidays;
"Occupant"	"occupant" means any person who has the right to occupy any premises;
"Overhead line extension"	"overhead line extension" means any above ground extension from existing Company distribution facilities required to supply electric power for one or more customers adjacent to a public road, and/or for two or more customers not adjacent to a public road, and any such extension shall be deemed to terminate where the line ceases to be common to more than one customer;
"Overhead service extension"	"overhead service extension" means any above ground extension across private property or along a private road required to serve only a single customer;
"Owner"	"owner" is any person having title to the whole or any part of any premises and may include a joint owner, tenant-in-common, or joint tenant;

1.1 INTERPRETATION AND DEFINITIONS

"Permanent Service"	"permanent service" is one terminated on a permanent structure and which can be expected to remain in place without alteration for the useful life of the service. It may serve a conventional building, mobile home, or recurring seasonal service;
"Person"	"person" includes a government and a department, agency or commission thereof, corporation, partnership, firm, association, society, unincorporated entity and the heirs, executors, administrators or other legal representatives of a person;
"Power"	"power" means the time rate of generating or using electric energy, normally expressed in kilowatts;
"Power factor"	"power factor" means the ratio of real power, (kW) to apparent power (kV.A) for any given load and time. Generally it is expressed as a percentage ratio;
"Premises"	"premises" means a premises that is provided with electricity through a single meter and, as the context requires, either (a) a complete building such as an office building, factory or house; or (b) a part of a building such as a suite of offices in an office building or an apartment in an apartment building, and in such cases the part of the building occupied must be contiguous and include no space not controlled by the customer; or (c) a group of buildings served by one electric service and at its discretion accepted by the Company as one customer for billing purposes;
"Primary metering"	"primary metering" means metering on the high voltage side of the transformer supplying the customer;
"Public Road"	"public road" includes any rural road listed and maintained by the Department of Transportation or any road

Deleted: ,

1.1 INTERPRETATION AND DEFINITIONS

maintained by a municipality;

1.1 INTERPRETATION AND DEFINITIONS

“Retail Supplier”	“Retail Supplier” has the same meaning as under the *Electricity Act*, S.N.S. 2004, c. 25.
“Retail Supplier Licence”	“Retail Supplier Licence” means a Retail Supplier licence issued by the Board in accordance with the Electricity Act, S.N.S. 2004, c. 25 and regulations made thereunder, which permits a person to sell renewable low-impact electricity generated within the Province.
“RtR Customer”	“RtR Customer” means a Retail Customer who is acquiring renewable low-impact electricity from an LRS at an individual premises and is not receiving Bundled Service from NS Power at that premises.
“Residential Customer”	"residential customer" means any individual non-commercial customer receiving service under the Domestic Service Rate at his/her permanent or temporary place of residence;
“Secondary metering”	"secondary metering" means metering on the low voltage side of the transformer supplying the customer;
“Service line allowance”	"service line allowance" is the distance from the centre line of the road or existing line, whichever is nearer to the nearest point of attachment to the customer's electric service as determined by the Company;
“Temporary electric service”	"temporary electric service" includes any service supplied for a temporary purpose, and without limiting the generality of the foregoing includes picnics, concerts, sporting events, rallies, conventions, circuses, exhibitions and construction sites and facilities which will not result in permanent service connections, and any service required for less than one month;

Deleted:

Deleted: ¶

1.1 INTERPRETATION AND DEFINITIONS

"Unmetered"

"Wholesale Customer""unmetered" means a supply of electricity for which no metering device is employed to record either the power or energy supplied.

Deleted: Column Break

"Wholesale Customer" has the same meaning as under the Electricity Act, S.N.S. 2004, c. 25.

Deleted: Section Break (Continuous)

1.2 NO CONTRARY REPRESENTATION BINDING ON THE COMPANY

No agent, employee or representative of the Company shall have the authority to make any promise, agreement or representation, whether verbal or otherwise, which is inconsistent with these Regulations and no such promise, agreement or representation if made or given shall be binding on the Company.

1.3 INFRINGEMENT OF REGULATIONS

The Company may disconnect electric service, remove its property from a customer's premises, and terminate any agreement for the supply of electric power and energy or discontinue the provision of Distribution Access Service if the customer fails to comply with these regulations as amended from time to time or any other relevant statutory provision.

Any use of electricity in breach of these regulations disentitles the customer to all extended service considerations provided with the procedures for disconnection, removal of Company property, and termination of any agreement.

2.1 APPLICATION FOR ELECTRIC SERVICE

The Company shall only supply electric service to a Customer who is the owner, or occupant, of premises for which electric service is required. The supply of such electric service shall be in accordance with these Regulations, and at such Rates as may be applicable, from time to time.

RESIDENTIAL ELECTRIC SERVICE CUSTOMERS

Before supplying electric service to a Residential Customer, the Company may require the owner or occupant of the premises to complete an Electric Service Contract. If such person refuses to complete the Electric Service Contract, the Company may refuse to supply electric service to the premises or may discontinue the supply of electric service to the premises.

The Company may also refuse to provide electric service to the premises if:

(a) the person applying for electric service has an outstanding electric service account and satisfactory arrangements for settlement have not been made, or

(b) the person applying is an agent for another person, and that other person has an outstanding electric service account and satisfactory arrangements for settlement have not been made, or

(c) an occupant of the premises has an outstanding account incurred when occupying any premises at the same time as the person applying for service and satisfactory arrangements for settlement have not been made.

In situations where the Company does not require the Customer to complete an Electric Service Contract, the Customer may request that an Electric Service Contract be completed prior to the supply of electric service.

NON RESIDENTIAL ELECTRIC SERVICE CUSTOMERS

Electric service will only be rendered to a Non Residential Electric Service Customer upon the completion of an Electric Service Contract. This Electric Service Contract must be signed by an authorized officer of such non residential customer. If the Customer refuses or neglects to complete an Electric Service Contract, the Company may refuse to supply electric service or may discontinue the supply of electric service.

The Company may refuse to supply electric service if the Customer has an outstanding electric service account.

2.2 AGREEMENT

An Agreement is deemed to exist between a customer and the Company for the supply of electric power and energy or for the provision of Distribution System Access, as applicable, at appropriate rates and payment therefore in accordance with these regulations by virtue of:

(a) the customer applying and receiving approval for electric service; or

(b) the customer consuming or paying for electric service from a date that the customer who is a party to an agreement pursuant to clause (a) (the customer of record) moves out of the premises, in which case the customer of record shall remain jointly and severally liable for the electric service account up to the date the Company is notified that the customer of record wishes to terminate the supply of electric service to the customer.

For certainty, the provision of Distribution System Access is deemed to constitute an electric service from the Company.

2.3 CONNECTION OF ELECTRIC SERVICE

The customer shall be charged a fee for the connection or reconnection of electric service as set forth in the Schedule of Charges.

In cases where no physical connection (meter installation or seal removal) of electric service is required, but a new account is added to the Company's billing system, the customer shall be charged a standard connection fee in accordance with these Regulations for establishing his account and/or taking a reading from the meter.

The Company shall perform connections or reconnections of electric service during the Company's normal business hours. The Company may perform such connections or reconnections at other than normal business hours at an additional fee if requested to do so by the customer.

The customer is not to be charged the connection fee where the connection or reconnection is occasioned by a failure of the Company to comply with the Regulations.

2.4 ASSIGNMENT OF ELECTRIC SERVICE CONTRACT OR ACCOUNT

A purported assignment of an electric service contract or an electric service account is null and void unless such assignment is authorized and approved by the Company.

2.5 POINT OF SUPPLY AND POINT OF SERVICE

The Company shall determine the point of supply and the point of service to any customer.

Any additional costs incurred as a result of the customer's special electric service requirements shall be borne by the customer.

2.6 OVERHEAD LINE AND SERVICE EXTENSIONS

Line and service extensions shall be erected and owned by the Company. Where it is necessary to build on private property other than the customer's property, the customer is responsible for obtaining a registerable right-of-way in the Company's name and in a form satisfactory to the Company. Where it is necessary to build on the customer's property, the customer must grant to the Company a registerable easement in a form satisfactory to the Company.

In all cases involving private property, the customer is responsible for having the right-of-way suitably cleared of trees, bushes and undergrowth to the Company's satisfaction.

The Company will normally provide to its customers, a maximum of 92 metres of line or service extension, or 92 metres of line and service combined. The Company shall provide to a year round residence, which the Company is satisfied is the customer's permanent, primary, or principal residence, an additional 100 metres of line extension along a public road for each year that the residence has been continuously occupied prior to the request for service, to a maximum of 1,600 metres. The customer shall contribute to the cost of all extensions over and above these provisions.

However, in an area where line and/or service provisions previously existed, the Company shall provide a similar new extension at a reduced cost to the customer, based on the following formula wherein the indicated timeframes represent that period of time which has elapsed since the previous line/service facilities were removed.

Elapsed Time	Percent Customer Contribution
Up to 1 year	0
Year 1-2	20%
Year 2-3	40%
Year 3-4	60%
Year 4-5	80%
After 5 Years	100%

Where the new requirement represents or indicates an expansion or upgrade of the prior facilities, the reduced contribution will only be applicable to costs associated with an equivalent service provision.

2.6 OVERHEAD LINE AND SERVICE EXTENSIONS

A service extension is normally terminated on the customer's building. Should it be necessary to terminate a service on a pole, or if the customer, for any other reason, requires that the Company provide an additional pole not normally required in the opinion of the Company, the customer will be required to make a capital contribution towards the cost of a pole supplied, installed and owned by the Company. The customer must supply the weatherhead, conduit and meter base necessary to receive service.

2.7 ELECTRIC SERVICE AVAILABILITY AND STANDARD VOLTAGES

The Company shall maintain electric service to customers by providing distribution facilities and services designed and constructed to accepted Utility Engineering Standards, including one supply to each building.

Customers shall not use these facilities in a manner that will cause unacceptable interference to the Company's system, and/or adversely affect other customers served from the same facilities.

The following electric service voltages are to be considered as standard within the low voltage classification:

Single-phase, 3-Wire, 120/240 volts
Three-phase, 4-Wire, 120/208Y volts
Three-phase, 4-Wire, 347/600Y volts

In addition, three-phase electric service may be provided at other voltages with special permission. Customer contributions will be required if additional costs are incurred.

For voltage variation limits, refer to C.S.A. standard - CAN-C235-83 or any subsequent revision.

Customers requiring three-phase electric service with connected load of 15 kW and under will be required to pay to the Company a capital contribution, as set forth in the Schedule of Charges, to cover the extra cost of transformers that must be installed to serve the three-phase load. Such contribution is in addition to that assessed to cover required line extensions. Should the necessary line and transformer facilities already exist at the location in question, no contribution will be required.

The electric service voltage provided under the Domestic rate to self-contained dwelling units, duplexes, condominiums and small apartment buildings shall be 3-Wire, 120/240 volts, except where there is a legitimate requirement for three-phase electric service.

Electric service shall normally be limited to one secondary voltage supply per duplex or other multi-unit residential building.

Under Regulation 2.11, the Company may require an underground primary voltage supply to serve such a building.

2.7 ELECTRIC SERVICE AVAILABILITY AND STANDARD VOLTAGES

Commercial loads which can be adequately supplied by a 30 ampere, 2-Wire supply may be served 2-Wire, 120 volts.

The Company may, at no charge to the customer, install a recording instrument to check a customer's voltage at the customer's supply point.

If the Company is satisfied with the customer supply voltage and if the customer for the customer's own purposes requests a recording instrument be installed, a charge for the installation of such recording equipment shall be applied as set forth in the Schedule of Charges.

2.8 ELECTRICAL INSPECTION OF INSTALLATIONS

Every electrical installation within NSPI's service area shall be made in conformity with the Electrical Installation and Inspection Act (and regulations made thereunder), and Company standards. A wiring permit shall be obtained from NSPI before work is commenced with respect to new or existing installations. NSPI shall not be required to make a connection to any installation until it is satisfied that such installation is in compliance with all applicable regulations and standards and shall have the right to re-inspect any premises.

The appropriate charges shall be applied in accordance with the fees set out in Regulation 7.2 Schedule of Wiring Inspection Fees.

2.9 TEMPORARY ELECTRIC SERVICE

A customer requiring temporary electric service shall pay the Company for the electric service at the applicable rate and shall pay in advance the cost of installing and removing the electric service connection and any other related connection and reconnection costs, as set forth in the Schedule of Charges.

The minimum term temporary electric service for billing purposes, shall be one month; if the period of use in excess of one month includes a part of a month, the base charge and energy charge for the fraction of the month shall be billed to the exact day.

The Company shall have the right to limit the term of temporary electric service. This shall include the right to review the temporary aspect of the electric service and to determine if the electric service should be disconnected, retained as temporary or changed to a permanent electric service.

2.10 TRANSFORMER INSTALLATION

When in the Company's opinion, it is impractical to provide the customer's electrical requirements from existing Company facilities the customer must, on the request of the Company, provide suitable transformer(s) space on the customer's premises for the necessary transformers. The type and location of primary service equipment must be approved by the Company for each installation.

2.11 UNDERGROUND ELECTRIC SERVICES

Distribution Systems - The Company may supply, install, maintain and own underground distribution systems. A party requesting the installation of an underground distribution system will be required to make a capital contribution to the Company, equivalent to the difference in cost between the underground system installed and overhead distribution facilities it would otherwise provide.

Conversion of Existing Overhead Distribution Systems To Underground - A party requesting the conversion of an existing overhead system to underground shall be required to make a capital contribution to the cost of the conversion.

Secondary Services - The Company is not required to install underground secondary voltage services; however, in the event the Company installs an underground distribution system, consideration will be given towards the supply and installation of such electric services by the Company, at the customer's expense. The customer will be responsible for ownership, maintenance and replacement when necessary, except that in special circumstances such as may be encountered in a total underground urban system, it may be practical for the Company to own and maintain the total system including the secondary services. In the case of an individual underground residential service from a normal overhead system; the Company will allow the customer credit for the equivalent cost of an overhead service it would otherwise provide.

Primary Services - The Company will normally own the primary voltage cable in a customer-owned duct system. In the event that a primary service must be replaced, extended or repaired, the customer is responsible for any and all costs associated with the duct system. In this event, the Company will maintain service by temporary means but if it is deemed that service interruption results from failure of the duct system, such as might be caused by excavation in the area of the duct system, the customer will be responsible for temporary service costs as well as all costs associated with repairs to the service.

Replacement of Existing Systems - The Company will be responsible for costs associated with the best (generally lowest cost) supply option should an underground system (or any part thereof) have to be replaced. Where this option is another underground system the existing system would be replaced in kind. However, should the best option be overhead supply, and the customer wishes to continue to be served with underground service, the customer(s) will be required to make a new capital contribution, equivalent in cost to the difference between the overhead supply and the underground system.

2.12 REFUNDS OF CAPITAL CONTRIBUTIONS

Line/Service Extensions Less Than 184m

Customers will be provided with 92 metres of line/service extension at no cost, as provided for under Regulation 2.6. Any line/service extensions in excess of 92 metres will be at the cost of the customer. If any additional customers are connected to a contributed line/service extension, they will not be required to contribute to the shared portion of line, but will be responsible for the cost of any service extensions in excess of 92 metres. For each additional customer connected to a contributed portion of line within ten years from when the line was made available, the person who made the contribution will be entitled to 46 metres of equivalent line cost minus a 10% administration fee to a maximum of 90% of the total contribution.

Line/Service Extensions Longer Than 184m

Customers will be provided with 92 metres of line/service extension at no cost. Any line/service extensions in excess of 92 metres will be at the cost of the customer. If any additional customers are connected to a contributed line/service extension, they will be expected to contribute to the cost of any shared line plus contribute the cost of any dedicated line minus a credit for 92 metres of equivalent line cost.

Customers who have paid a capital contribution will be entitled to a refund each time additional customers are connected to the line within ten years of the date of the customer's capital contribution. The refund will be the difference between the net capital contribution paid to date and what would have been required if the additional customers had attached at the time the contribution was paid. Any refunds will be reduced by 10% as an administration fee. The maximum refund a customer can receive is 90% of the original contribution.

Notwithstanding the above, no refunds of capital contributions associated with any line/service extension will be made after such line/service extension is more than fifteen years old.

3.1 FARMING OR FISHING LOAD THAT MAY QUALIFY FOR THE DOMESTIC SERVICE RATE

Farming or fishing units may receive electric service at the domestic rate providing the following conditions are met:

(a) each unit may have connected up to 200 amps single or combined service capacity, at voltages up to 240 volts, billed on the domestic rate; service capacity in excess of the 200 amp allowance will be billed at the applicable Non Domestic rate; and

(b) the service capacity must be served by no more than three separately metered services.

The residence or residences will be metered separately for the purpose of this regulation.

A single metered service with capacity in excess of 200 amps will be billed on the applicable Non Domestic rate.

Service capacity of an accessory farm or fishing building served through the residence meter will be considered part of the unit total.

3.2 PREMISES JOINTLY USED FOR RESIDENTIAL AND COMMERCIAL PURPOSES

When a customer uses part of his premises as a residence and part for a small store or office, or other commercial use, the Domestic rate shall be applied to the entire premises, provided the connected load in the commercial portion, excluding space heating and air conditioning, is not greater than 3kW. Otherwise, the applicable Non Domestic rate shall be applied to the entire premises, or, at the customer's option, the residential electric service and the commercial electric service shall be separated and the Company shall install one meter for each, at which time the residential electric service shall be billed at the Domestic Service rate and the commercial electric service at the applicable Non Domestic rate.

3.3 SEASONAL ELECTRIC SERVICE

The contract period for all seasonal accounts is from May 1 to October 31, in any calendar year. Electric service to seasonal customers will remain connected during the winter period from November 1, to the following April 30 and the base charge will not be billed during these winter months, nor will bills be rendered. Energy used beyond October 31 will be billed on the first regular billing after May 1, or the final bill, whichever comes first. A disconnection charge, as set fort in the Schedule of Charges, will be applied when the seasonal electric service is physically disconnected at the request of the customer. The standard connection charge will apply if electric service is subsequently reconnected.

Seasonal domestic electric service will apply to any self-contained electric service (i.e. summer homes, cottages, hunting or fishing camps), occupied on an intermittent basis, and the Company is satisfied that it is not the customer’s permanent or primary residence.

Seasonal commercial electric service will apply to self-contained seasonal commercial businesses (i.e. campgrounds, ice cream barns, tourist bureaus, fixed and mobile canteens, kiosks, and federal/provincial park entrance booths). Seasonal commercial service is only available to customers taking service under the Small General Rate and the Company is satisfied that the electric service is being used on a seasonal basis, not year round.

3.4 ELECTRIC SERVICE TO MOBILE HOMES

Mobile Homes will only be supplied with permanent electric service (other than when used in conjunction with construction projects).

The Mobile Home owner must satisfy the Company that he has obtained all required Municipal approvals for the location and occupancy of the Mobile Home.

3.5 STREET AND AREA LIGHTING

The Company may on request supply and maintain standard street and area lighting units including fixtures, automatic switch, all electric energy and any brackets and hardware required for regular mounting of the lighting unit on an existing pole or suitable mounting location. The Customer will be responsible for any cost in excess of those specified and for providing any easements required for private property.

An individual customer requesting street and area lighting services must agree to a minimum term of one year.

When a customer requests that street lighting be changed to provide higher illumination or improved luminous efficiency, he shall be required to pay the advancement cost of replacement and, in the case where the original fixture cannot be reused, the cost of the remaining life value as determined by the Company.

Where the existing lighting is fully depreciated but where there is useful life remaining, the Company may after taking all relevant circumstances and costs into account, delay the replacement of such lighting.

Street and area lighting rates will be billed along with the regular electric service account.

Costs incurred by the Company for repairs and replacement due to vandalism will be charged to the customer. Where a customer refuses to pay such costs, the Company may refuse to install a replacement fixture at that location.

3.6 NET METERING SERVICE

3.6.1 Definition

Net Metering service is a metering and billing practice that enables electricity consumers to generate electricity from renewable, low-impact, generators to offset part or all of their own electrical requirements. Excess self-generation, over a customer's own-consumption needs, is credited against purchased energy for billing purposes over a period of one year. Any surplus generation remaining at the end of a one year period will be purchased by the utility at the appropriate retail rate. Customers taking this service will be referred to as "customer-generators".

3.6.2 Availability

I. Net Metering Service is available to all NSPI bundled service customers who are served from NSPI's Distribution system (ie: 24,940 volts or less), who are billed under NSPI's metered service rates, who install a qualifying generating facility, as defined under item b) in the Special Conditions Section 3.6.6. The maximum capacity of the customer's generating facility will be sized to meet the expected annual consumption of the customer and will fall into one of two classes of service.

   i. Class 1 Net Metering Service means a generating facility of aggregate nameplate capacity of up to 100 kW

   ii. Class 2 Net Metering Service means a generating facility of aggregate nameplate capacity of more than 100 kW but less than or equal to 1000 kW.

      b) Net Metering is not applicable for Unmetered services.

      c) The customer must provide a written request to take the Net Metering service.

The service is available on a first-come, first-serve basis. For certainty, Net Metering Service is not available to a Customer who is acquiring renewable low-impact electricity from an LRS.

3.6.3 Applicability

The service is applicable to any metered electric service accounts which are electrically connected to the same NSPI Distribution Zone as the generator, and which are owned by the same customer.

3.6 NET METERING SERVICE

3.6.3.1 Distribution Zone

The Distribution Zone is defined as all NSPI distribution feeders emanating from a single distribution supply transformer within a substation. The Company reserves the right to broaden this definition if in the opinion of the Company this is justified by a customer-specific circumstance and is consistent with the spirit of the intent of this regulation.

3.6.3.2 Customer

For the purpose of the Net Metering regulation "customer" is defined as a single legal entity, and does not include a Customer who is acquiring renewable low-impact electricity from an LRS.

3.6.4 Billing

a) Customer-generators will be billed under the otherwise-applicable metered rate schedules.

b) If in a given billing period the electricity supplied to NSPI's grid by the customer-generator exceeds that supplied to the customer by NSPI, the customer shall be billed only for the applicable non-KWh monthly charges and shall have the excess self-generation "banked" as energy credits to be applied against future bills over a period not exceeding 12 calendar months..

Banked Excess Self-generation = Self-generation supplied to NSPI - Purchased energy from NSPI.

c) If in a given billing period the combined total of the electricity supplied to NSPI's grid by the customer-generator and the "banked" energy credits from the previous billing periods is less than the electricity supplied to the customer by NSPI, NSPI will bill the customer for the Net Purchased Energy Requirement and for the applicable non-KWh monthly charges.

Net Purchased Energy Requirement = Purchased energy from NSPI – (Self-generation supplied to NSPI + "Banked" energy credits).

d) "Banked" excess self-generation will create an energy credit to be held by the customer-generator and will carry over until the customer's annual anniversary date at which time the energy credit will be set to zero with compensation to the customer-generator priced at the appropriate retail rate. Where the customer rate structure includes only one energy charge, the surplus credit will be priced at that energy charge. Where the customer rate structure declining block energy charges, the surplus energy will be priced at the energy charge applicable to the additional kilowatt hours. Compensation will be exclusive of any amount representing Demand Side Cost Recovery Rider charges. The customer-generator will set a permanent annual anniversary date at the time of subscription to the Net Metering service. No changes to the annual anniversary date will be permitted once set. If service is discontinued, any outstanding banked energy credits will be priced in the same manner as those at the time of the annual anniversary date and paid back to the customer-generator.

e) Any interim energy credit balances on a customer-generator's account other than those covered under item d) will not have any cash value or be convertible to cash.

f) Should a customer-generator be billed under more than one electric account connected to the same Distribution Zone as the generating facility, the customer will propose a method to apportion its surplus generation against its consumption under multiple accounts for billing purposes. The customer will either designate the order in which the apportionment of surplus generation is to be applied to individual accounts or nominate the fraction of surplus generation to be apportioned to each account or choose a combination of both approaches. Should a customer generator subscribe to more than one net metering application within the same Distribution Zone, each account will have only one generating facility assigned to it for billing purposes. The proposed method of surplus allocation and the account assignment to generating facilities will be approved upon the subscription to the Net Metering service and will stay in effect until such a time when customer submits a written request for change. NSPI may, at its sole discretion, approve such changes provided they remain in place for a minimum of 12 months

g) For Accounts billed under domestic time-of-day service, NSPI will measure and bank self-generation sold to the grid by distinct time-of–use periods for billing purposes. Any surplus generation remaining at the time of the annual anniversary date or at the time the service is discontinued will be compensated by distinct time-of-use period at the appropriate time-of-use energy charges.

h) Any environmental credits which may be created through the generation of energy through Net Metering will be held by NSPI.

3.6 NET METERING SERVICE

3.6.5 Metering

a) Net energy metering shall be accomplished using a single meter capable of registering the flow of electricity in two directions as approved by Measurement Canada. If the eligible customer-generator's existing electrical meter is not capable of measuring the flow of electricity in two directions, the customer-generator shall be responsible for incremental meter costs and any other related costs.

i. If NSPI determines that the flow of electricity in both directions cannot be reliably or safely determined through use of a single meter, NSPI may require that separate meters be installed. Such metering will be at the customer's cost.

b) In addition to a), for Class 2, Net Metering an additional metering system dedicated exclusively to measuring the generator's output is required.

3.6.6 Special Conditions

a) Special conditions in this regulation do not supersede, modify or nullify special conditions accompanying the otherwise-applicable metered rate schedules.

b) A Qualifying generating facility must meet the following requirements:

i. Utilizes only a renewable, low-impact source of energy as defined in the Renewable Electricity Regulation for the purposes of section 3A of Chapter 25 of the *Electricity Act*.

ii. Has a manufacturer's nameplate rating of not more than 1,000 Kilowatts, which NSPI has the right to verify through inspection or testing.

iii. Is located within the same Distribution Zone as all of the customer's premise(s) for which the customer is requesting Net Metering electric service in conjunction with this facility.

iv. Subject to special condition b) iii), at the discretion of the customer, the generator may be connected to the grid either at any of the existing points of delivery of purchased power from NSPI or at a separate point if approved by NSPI. If a separate point of delivery is used, all additional costs will be the responsibility of the customer-generator.

3.6 NET METERING SERVICE

v. Net Metering facility shall meet all applicable safety and performance standards established by Measurement Canada, the Canadian Electrical Code, and NSPI's guidelines.

4.1 INSTALLATION AND ACCESS TO METERS

Representatives of the Company shall have the right of access to connect, remove, read or test meters or other appurtenances at all reasonable hours. When suitable arrangements cannot be made for the Customer's meter to be read at the normal reading time the Company may require the installation of an outside meter. The cost of such installation shall be borne by the Customer.

If in the Company's opinion the meter is located in such a position that it is subject to damage, the Company may instruct the Customer to suitably protect the meter or move the meter to a new location, and the cost thereof shall be borne by the Customer. If the Customer fails to follow the Company's instructions, the Company may take the necessary steps to protect the meter. The Customer shall reimburse the Company for any costs so incurred by the Company.

In all new residential premises entrance wiring shall be installed so that an outdoor meter may be used.

Any Customer with an existing indoor meter in a residential premises, who makes a change in the electric service entrance conduit and wiring, is required to arrange for an outdoor meter unless permission is granted by the Company to do otherwise.

When an addition to premises results in an outdoor meter being located inside the building, then the meter must be relocated outside.

Provision must be made by the Customer for the use of socket-base meters in all cases.

If, in the opinion of the Company, any Customer has failed to comply with these requirements the Company shall, after written notice to the Customer, discontinue electric service to such Customer. The standard connection charge will apply if service is subsequently reconnected.

4.2 METERED ELECTRIC SERVICE - UNMETERED ELECTRIC SERVICE

The consumption of electric service supplied by the Company shall be recorded by the use of the appropriate meters, provided however that the Company may provide unmetered electric service in those instances where consumption is low, constant and readily determined.

4.3 MULTIPLE METERING POINTS

Where, because of the customer's requirements, it is necessary to use more than one metering point, then the power and energy recorded on each meter shall be billed separately and at the rate applicable to the loads served at each meter.

4.4 PRIMARY METERING

Metering will normally be at the secondary side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional cost of the primary metering.

4.5 CONVERSION OF SINGLE FAMILY RESIDENCE

If a Domestic Service customer permits additional living quarters for other parties in the same premises or a separate establishment to be connected through his meter, the Company has the option of multiplying the base charge, where applicable, and the kilowatt hours in each block by the number of dwelling units involved at the rate applicable to the main electric service, or disconnecting the electric service supplying the customer until the electric service to the other parties has been connected through an additional meter in the regular way.

4.6 THEFT OF ELECTRIC POWER AND ENERGY

Where there is evidence of theft of electric power and/or energy, the customer's electric service may be disconnected. Such person or persons responsible may be liable for prosecution under the Criminal Code of Canada.

In such cases, customers with indoor meters may be required to move the meter to an outdoor location.

4.7 POWER FACTOR CORRECTION

When charges are based on maximum demand measured in kilowatts, the customer shall maintain a power factor of not less than 90%.

Where the Company determines that a customer's power factor is less than acceptable, the Company shall have the right to meter the customer in kV.A demand and to calculate a kW billing demand based on a power factor of 90%.

4.8 INSPECTION OF CONNECTED LOAD

Representatives of the Company shall have the right to enter the premises of all customers during all reasonable hours for the purpose of inspecting connected load.

4.9 COMPANY'S RIGHT TO REFUSE PROVISION OF ELECTRIC SERVICE

Notwithstanding any other provision of these Regulations, the Company may refuse to provide electric service, or may disconnect the supply of any electric service at such times, and for such lengths of time, as the Company may deem to be appropriate if:

(1) in the Company's opinion a state of emergency exists; or

(2) in the Company's opinion such action may be necessary to avoid injury or damage to persons or property, whether such property be the property of the Company, Customers of the Company, or otherwise.

5.1 METER READING

When reasonably possible, meters shall be read bi-monthly; however, the Company may read meters on a monthly basis.

POST CARD METER READING

In the event that the Company is unable to obtain meter readings, for billing purposes, during the Company's normal business hours, having exercised due diligence in the usual practice of meter reading, it may leave a prepaid postage card on the premises which will indicate the normal reading date, and upon which the Customer shall without delay record the reading of the meter, thereafter immediately returning the card to the Company.

ESTIMATED METER READING

If the Company is unable to obtain a meter reading due to circumstances beyond its control, or due to the failure of the Customer to return a post card reading, then the amount of power and energy used by the Customer shall be estimated by the Company using the best available data. In the event that estimated meter readings are required five (5) consecutive times, then the Customer shall make suitable arrangements to ensure that the meters are read by the Company during the Company's normal business hours. Should the Customer fail to make such suitable arrangements, the Company may disconnect the supply of electric service to the Customer or may require that the Customer relocate the meter in accordance with the Regulation 4.1.

In the event that actual meter readings are obtained subsequent to estimated readings, the Company shall make the necessary adjustments.

METER READING IN RURAL AREAS

Where electric service is supplied to a Customer in a rural area, the Company may adopt a post card meter reading system of monthly or bi-monthly meter reading. Under such system, the Company shall supply the Customer with prepaid postage cards upon which the Company shall indicate the date upon which the meter shall be read by the Customer ("reading date"). The Customer shall record on the postcard the reading showing on the meter as of the reading date and shall immediately return the card to the Company. In these circumstances, the Company may consider postcard meter reading to be actual meter readings.

5.1 METER READING

ESTIMATED METER READINGS IN RURAL AREAS

In those rural areas where the post card meter reading has been adopted, should the Customer fail to return the prepaid postage card, then the amount of power and energy used by the Customer shall be estimated by the Company using the best available data.

Notwithstanding the foregoing, an actual reading must be taken by the Company at least once within a twelve-month period for meters which are read bi-monthly and once within a six-month period for meters which are read monthly.

5.2 BILLING

Except for Domestic Rate Customers who are on the Residential Budget Plan or the Interim Bill Plan, the Company shall render bills on a bi-monthly basis when meters are scheduled to be read or are normally read bi-monthly and on a monthly basis when meters are scheduled to be read or are normally read monthly.

In computing bi-monthly bills, the applicable monthly base and/or demand charge and energy blocks shall be doubled.

Initial and final bills for electric service shall be calculated based on the actual days of service.

Bills which are based on estimated readings shall be identified as such.

5.3 ALTERNATIVE BILLING PLANS

A) BUDGET PLAN (Not available to a Customer who is acquiring renewable low-impact electricity from an LRS)

A customer (excluding a Customer who is acquiring renewable low-impact electricity from an LRS) may make application to the Company, at any time during the year, for the Budget Plan which has a twelve-month budget period. All customers will have a January anniversary date, regardless of their month of entry to the Plan.

A Budget Plan customer shall be billed monthly. The monthly billing shall be based upon the average kilowatt hour usage of the customer at the premises to which the application relates for the preceding budget period, as adjusted for normal weather. If the customer does not have the required budget period history at the premises, the Company shall estimate the amount of the monthly bill.

The Company shall read the meter on a monthly or bi-monthly basis and at the end of the budget period of electric service, the Company shall render a bill which shall show the new budget payment amount for the next twelve months and show the amount owing based on the meter readings less the amounts paid. The new budget payment amount will be increased or decreased by an amount sufficient to eliminate the difference between amount owing based on the meter readings less the amounts paid. Alternatively, if the total of the billing based on the meter readings is greater than the total of the monthly payments, the customer may pay the difference to the Company; or if the total of the monthly payments is greater than the billing based on the readings, the customer may request a refund of the difference.

The Company may refuse to place a customer on the Budget Plan or remove an existing customer from the Plan if the customer has an unsatisfactory credit history. Domestic customers who enter into a Payment Agreement with the Company are eligible to be placed on the Budget Plan with blended payments consisting of monthly usage and arrears. The Company will issue information to the customer on a monthly or bi-monthly basis, calculated on the readings. Such information shall be for the purpose of informing the customer of the actual charges which may be applicable to the customer's account.

B) GROUP BILLING PLAN (Not available to a Customer who is acquiring renewable low-impact electricity from an LRS)

5.3 ALTERNATIVE BILLING PLANS

A customer (excluding a Customer who is acquiring renewable low-impact electricity from an LRS) may request billing under the Group Billing Plan at any time.

Under this plan the customer will be issued a group bill on Tuesday of each week (Wednesday, if Monday is a holiday). This group bill will contain all of that customer's accounts that were regularly billed during the previous seven days.

Group bills are due on the billing date. Those that are not paid within seventeen (17) days are subject to an interest charge in accordance with Regulation 7.1 (h).

In the case of a dispute regarding any part of the group bill, the undisputed portion must be paid in full. Adjustments would be made as appropriate where the disputed amount is resolved in the customer's favour.

5.4 PAYMENT OF ACCOUNTS AND INTEREST CHARGES

PAYMENT OF ACCOUNTS

Bills are due on the billing date. Service to a customer whose bill remains unpaid for a period of thirty days after the billing date is subject to disconnection for non payment. Payments on accounts in arrears shall be credited first to the most outstanding of these amounts. Where such a payment only reduces the outstanding balance due, a customer must make satisfactory arrangements for payment of the balance prior to the expiry of a collection notice in order to avoid disconnection without further notice.

Bills may be paid by mail, at any Chartered Bank and most Credit Unions (in person, by telephone banking or electronically), at designated Company offices or through authorized payment agents.

In addition, the Company may permit the customer to have bills sent directly to the customer's bank for payment under the terms of a Pre-Authorized Payment Plan. NS Power may also permit payment by credit or debit card (plus any applicable fees) through an authorized payment agent.

AUTOMATIC PAYMENT PLAN (PAY SMART)

A customer may make application to the Company at any time to be placed on the Automatic Payment Plan. Under the Automatic Payment Plan, the Company withdraws funds from the customer's designated account based on the due date to cover the billed amount. The customer will be removed from the Automatic Payment Plan if there have been two occurrences of insufficient funds on the account.

BI-MONTHLY BILLS - INTEREST CHARGES

Bills which are issued on a bi-monthly basis and which are not paid within thirty (30) days after the billing date shall be subject to an interest charge as set forth in the Schedule of Charges. The amount due within the thirty (30) day period and the effective date of the interest charge shall be clearly shown on the bill.

NOTICE TO CUSTOMERS IN ARREARS

NSPI must provide notice to customers who have bills thirty days overdue, and the notice may be automated and must be postmarked no later than the day the bill becomes 30 days overdue stating:

Your account is in default. Options for repayment and a payment plan are available to you. As soon as possible, contact us to find out what your options are @ [NTD insert proper email address and phone number.

MONTHLY BILLS INCLUDING RESIDENTIAL BUDGET PLAN - INTEREST CHARGES

Bills which are issued on a monthly basis, including those rendered under the Residential Budget Plan, and which are not paid within twenty (20) days after the billing date shall be subject to an interest charge as set forth in the Schedule of Charges. The amount due within the twenty (20) day period, and the effective date of the interest charge shall be clearly shown on the bill.

INTERIM BILLS - INTEREST CHARGES

The interest charges shall not be applicable on interim bills issued under the Interim Bill Plan.

5.5 BILLING ADJUSTMENTS

When a customer disputes the amount of electricity consumed from the meter, the Company shall:

a) Initiate a check on the meter reading to ensure the original reading was correct and advise the customer.

b) If the customer is not satisfied, the Company shall do an "in position" test on the meter to verify the reading is within the allowed tolerances, and advise the customer of the results.

c) If the Customer is still not satisfied, the Company will advise the Customer he/she may request an independent meter test to be performed by Industry Canada (see Regulation 6.7).

CUSTOMER UNDERBILLED

Should it be necessary for the Company to make a billing adjustment as a result of a customer being underbilled, for any reason, such adjustment for the amount of electric power and energy consumed in excess of that recorded on the meter, shall be estimated by the Company. The customer shall be responsible for payment of such amount, provided however, the billing adjustment shall be limited to a period not in excess of six (6) months prior to the last scheduled regular meter reading date.

Notwithstanding the above, in the event that a billing adjustment is a result of the customer's illegal or wilful interference with, or damage to, equipment used to record the consumption of electric power and energy, then the billing adjustment shall not in such circumstances be limited to a six (6) month period prior to the last scheduled meter reading date; rather, the customer shall be responsible for payment of such amount from the date of such interference or damage.

CUSTOMER OVERBILLED

Should it become necessary for the Company to make a billing adjustment as a result of a customer being overbilled, the following time frames for the adjustment are used to calculate the overbilling as per the Electricity and Gas Inspection Act, R.S.C. 1985, c.E4 as amended.

5.5 BILLING ADJUSTMENTS

1. Where the error is caused by a meter registering outside allowable limits, the overbilling is calculated from the beginning of a 3 month period prior to the customers request to Industry Canada to test the meter or from the date on which the meter was last sealed if the sealing occurred within that period.

2. Where the overbilling is identified and the meter is more than 3 months past due for reverification, the overbilling shall be calculated from the date when reverification was due.

3. Where the overbilling has been caused by an incorrectly installed meter, or an incorrect use of registering the meter or an incorrect multiplier; the overbilling is to be calculated from the date of installation. This type of overbill situation takes precedence over 1 and 2 above.

6.1 DISCONNECTION OF ELECTRIC SERVICE

(a) REASONS FOR DISCONNECTION

Subject to the requirements of these regulations the Company may disconnect service to a customer for one or more of the following reasons:

(1) non-payment of a delinquent account;

(2) unauthorized interference with or diversion of use of the Company's service situated or delivered on or about the customer's premises;

(3) failure to comply with the terms and conditions of a Payment Agreement;

(4) refusal to grant access at reasonable times to equipment installed upon the premises of the customer for the purpose of inspection, meter reading, maintenance and replacement;

(5) misrepresentation of identity for the purpose of obtaining utility service;

(6) refusal of service according to regulation 2.1;

(7) violation of any other rules of the Company on file and approved by the Board which adversely affects the safety of the customer or other persons or the integrity of the Company's energy delivery system;

(8) failure to pay a deposit as requested.

(b) NOTICE REQUIREMENT

(1) Electric service to a customer may be disconnected twelve (12) days after service upon the customer of a written notice of disconnection. Service of such notice may be by personal service, leaving a notice at the last known address of the customer or by first class mail. Where service is by first class mail such service shall be deemed complete upon the second day following the date of mailing.

(2) The customer shall be entitled to discuss the matter with the appropriate Company personnel before disconnection.

(3) If a customer, who has outstanding arrears from an electric service account, applies for and receives electric service, the Company may, upon

6.1 DISCONNECTION OF ELECTRIC SERVICE

giving twelve (12) days notice of disconnection, as aforesaid, disconnect the customer's active electric service.

(4) If a customer fails to pay a deposit or make satisfactory arrangements to pay a deposit, the Company may, upon giving twelve (12) days notice of disconnection, as aforesaid, disconnect the customer's active electric service.

(c) CONTENTS OF NOTICE

The notice of disconnection shall state the following:

(1) in bold-face at the top of the notice, "Disconnection Notice";

(2) the date on or after which disconnection will occur;

(3) that if the customer disputes the reason for disconnection a complaint may be made to the Dispute Resolution Officer and that the Board will hear an appeal from his decision;

(4) the address and telephone numbers of the Dispute Resolution Officer and the Board;

(5) that, if the customer is unable to pay the full amount shown before the date set out in the notice, the customer may be entitled to enter into a Payment Agreement with the Company.

6.2 RULES GOVERNING DISCONNECTION

A) TIME OF DISCONNECTION

The Company may disconnect the electric service to a customer on, or after, the date specified in the notice of disconnection and only during normal business hours.

Electric service shall not be disconnected on a day, or a day immediately preceding a day when the general services of the Company are not available to the public for the purpose of reconnecting a disconnected electric service.

The Company shall not disconnect electrical service to a domestic customer when the weather temperature is 0 degrees Celsius or below or forecast to be 0 degrees Celsius or below anytime in the week following the planned disconnection.

B) MANNER OF DISCONNECTION

Prior to the proposed date of disconnection the Company shall make reasonable efforts to contact the customer, to determine whether the customer has satisfied the outstanding account or is willing to make satisfactory arrangements to settle the outstanding account. If such contact is made and payment is not or has not been made and satisfactory arrangements for payment have not been made, the Company may disconnect the electric service. If such contact cannot be made the Company shall attempt to contact the customer or other responsible adult upon the premises served by the electric service account. If the Company is unable to contact such persons upon the premises, a written notice shall be left in a conspicuous location or the written notice shall be delivered by priority mail requiring signature. Either notice shall state the date and time after which electric service will be disconnected unless the amount, specified for the outstanding account is satisfied or satisfactory arrangements made to settle the outstanding account and thereafter the Company may disconnect the existing electric service.

When either notice is given, the customer will be charged the appropriate collection charge as set forth in the Schedule of Charges.

Should it be necessary for a Company representative to visit the customer for the purpose of disconnecting electric service and the service is not then disconnected the customer will be charged the standard collection charge as set forth in the Schedule of Charges, for each such visit.

When electric service is disconnected and the Company has not established contact with the customer, or other responsible person, the Company representative shall leave a notice upon the premises advising the customer of the fact that electric service has been disconnected and stating the address and phone number of the Company's office which should be contacted by the customer.

6.3 MEDICAL EMERGENCY

The Company shall postpone disconnection of electric service to a customer for a period not to exceed 14 days after the disconnection would normally be permitted under these Regulations if the customer produces a physician's certificate, stating that disconnection will aggravate a serious medical condition of the customer, a member of the customer's family or a permanent resident of the premises where electric service is to be disconnected.

6.4 DISPUTED BILLING FOR ELECTRIC SERVICE

(1) Where a customer advises the Company that all or a portion of his bill or any matter relating to the provision of electric service is in dispute, the Company shall:

(a) record the date, time and place where the complaint is made;

(b) promptly investigate the matter in dispute;

(c) upon completion of the investigation, advise the customer of the results thereof; and

(d) attempt to resolve the matter in an informal manner.

(2) In the event that a customer disputes a portion of a billing, then the customer shall pay or make satisfactory arrangements to pay the amount of arrears which is not in dispute, to the Company, within five days of the date upon which the customer advises the Company of the dispute or the due date, whichever is later. Failure of the customer to pay or make satisfactory arrangements to pay to the Company the amount of arrears which is not in dispute, as set out above, shall constitute a waiver of the customer's rights to dispute the matter, and the Company may then proceed to disconnect the electric service provided in accordance with these regulations. Should the customer and the Company be unable to accurately determine the amount which is not in dispute then the entire amount of the bill, or bills, at issue shall be deemed to be in dispute.

(3) If the Company and the customer are unable to resolve a dispute in a mutually satisfactory manner, the customer may contact the Company's Dispute Resolution Officer or his designate. The Dispute Resolution Officer shall be appointed by the Company and have no direct line responsibility for billing, credit, collection or electrical supply to the customer.

(4) The Dispute Resolution Officer shall consider both sides and after review, render his decision promptly. The customer has 12 days from notification of the decision to appeal, in writing, to the Board. No disconnection in relation to a disputed bill shall be made until twelve days after the decision of the Dispute Resolution Officer is given and the customer is notified thereof.

6.5 PAYMENT AGREEMENT

(1) In those cases where the customer does not dispute liability for the amount in arrears, or where the Company and the customer arrive at a settlement of the dispute, the Company may, if the customer is unable to pay the amount in arrears, permit the customer to pay the full amount over a period of time.

(2) DOMESTIC CUSTOMERS

(a) In those cases where a domestic customer does not dispute liability for the amount in arrears and the domestic customer is unable to pay the amount in arrears, the Company shall offer the customer the opportunity to enter into a Payment Agreement that provides for reasonable terms and conditions of repayment over time of the amount in arrears, consistent with the customer's ability to pay.

(b) Where the Company and the customer agree to terms and conditions of repayment of the amount in arrears within 30 days, no written agreement is required. Where payment arrangements extend beyond 30 days, the Company shall offer the customer a written Payment Agreement. A domestic customer is eligible for a Payment Agreement to be extended to 24 months. The Company shall communicate to the customer that a Payment Agreement for repayment of arrears over 24 months is available depending on the amount of arrears, whether there have been previous defaults upon Payment Agreements entered into pursuant to these Regulations within the last 24 months, and the customer’s ability to pay. No further notice of disconnection shall be sent to the customer unless the customer fails to comply with the terms and conditions of the Payment Agreement or is otherwise liable to disconnection for any of the reasons under Regulation 6.1(a), in which case, if the Company decides to disconnect, the Company shall serve a written notice of disconnection as provided for in Regulation 6.1(b).

(c) Once a Payment Agreement has been entered into, further interest, starting from the date the negotiations with respect to the Payment Agreement began, will not accrue on a domestic customer’s account so long as the terms of the Payment Agreement are being met.

(d) A Payment Agreement may be amended between a domestic customer and the Company, except where:

i. The account is in arrears for an amount equivalent to more than 6 months usage;

6.5 PAYMENT AGREEMENT

ii. There has been no payment on the account for 3 months; or
iii. The customer has not made the 2 most recent payments required under the Payment Agreement.

(3) FORM OF PAYMENT AGREEMENT AND PROCEDURE

Every Payment Agreement shall be in writing and shall be signed by the customer and an authorized representative of the Company. The Payment Agreement shall be prepared by the Company and shall contain a schedule of payments calculated to eliminate the liability of the customer. The Payment Agreement shall contain the following in bold face type, in print at least two sizes larger than any other print on the Agreement, and in the space immediately preceding the space for the customer's signature;

6.5 PAYMENT AGREEMENT

"IF YOU ARE NOT SATISFIED THAT THIS PAYMENT AGREEMENT ACCURATELY REFLECTS THE TERMS OF THE AGREEMENT REACHED WITH NOVA SCOTIA POWER, DO NOT SIGN.

> IF YOU DO SIGN THIS PAYMENT AGREEMENT YOU WAIVE YOUR RIGHT TO DISPUTE THIS MATTER FOR ANY REASON EXCEPT THE NOVA SCOTIA POWER'S FAILURE OR REFUSAL TO FOLLOW THE TERMS HEREOF.
>
> FAILURE TO COMPLY WITH THE TERMS OF THIS AGREEMENT MAY RESULT IN DISCONNECTION OF ELECTRIC SERVICE."

6.6 DEPOSITS

When requested by the Company, a customer shall deposit with the Company a sum equal to estimated charges for three months' service when billed bimonthly, and approximately two months' when bills are rendered monthly. This deposit is to be held by the Company as security for the payment of its bills. When the customer ceases to use the service and pays all bills, or the Company deems a deposit is no longer required, the deposit with interest is to be returned to the customer, as set forth in the Schedule of Charges. The Company shall review its customer deposits every two years with a view to determining whether or not a deposit is still required.

The Company shall inform the customer that the requested deposit can be made in equal monthly installments and paid over 12 months.

If a customer does not pay a deposit as requested by the Company, the Company may refuse to provide service or disconnect the customer's service.

RESIDENTIAL ELECTRIC SERVICE

The Company shall not require a deposit from a residential customer, unless one of the following conditions has occurred within the last two years of service from the Company:

(a) The customer does not have a previous credit history with the Company and does not have an acceptable external credit rating.

(b) The customer's service has previously been disconnected for non-payment.

(c) The customer refuses to supply necessary customer data to meet our requirements.

(d) The customer has obtained or attempted to obtain service through misrepresentation, tampering, theft, interference, or any other related illegal means.

(e) The customer has been delinquent requiring disconnection communication and/or field collection visits or has presented cheques that were returned noted N.S.F.

(f) The customer has a record of moving without notice.

(g) The customer has filed for bankruptcy and has chosen to claim his electric service account in the bankruptcy.

6.6 DEPOSITS

(h) Customers receiving social assistance or other similar types of income security payments shall not be required to make deposits unless they have a history of a bad credit relationship with the Company

Notwithstanding items (a)(h) above, if the customer is unable to pay a deposit, the Company will waive the requirement for a deposit. A deposit will be required if, following a waiver of the deposit, the customer has a subsequent default in payment, or is seeking reconnection following having been disconnected for non-payment and having had a security deposit previously waived with respect to the account that was disconnected.

NON RESIDENTIAL ELECTRIC SERVICE

When a non Residential customer applies for service, the Company will normally require a deposit. This includes non residential customers on the Domestic Service Rate.

A deposit from a Business or Commercial customer may not be required if any of the following conditions apply:

(a) The customer has existing accounts which have been paid satisfactorily for a period of not less than two years, in which case the account(s) are considered to be established as credit worthy.

(b) The customer is a subsidiary of an established existing customer and that parent organization has guaranteed payment of the account and has been approved by the Credit & Collections Department.

(c) The customer is a Federal, Provincial or Municipal Government body with whom we have had no recent collection activity or difficulties.

6.7 DISPUTE TEST

Upon notice from Industry Canada, the Company will remove the meter and ship it to Industry Canada (seal intact) for testing. If the meter, when tested, is found to be accurate, the customer is responsible for any outstanding amount. Also, if the meter is found to be accurate, the Company will charge the customer a fee as outlined in the Schedule of Charges 7.1, Section 1.

6.8 RETURNED CHEQUE CHARGE

A returned cheque charge as set forth in the Schedule of Charges shall be applicable to the customer's account when:

a) a cheque tendered to the Company in payment of an account is returned by the bank/financial institution uncleared; or

b) payment through a pre-authorized or automatic payment plan has been reversed or dishonoured by the bank/financial institution.

Where it is established that the cheque, pre-authorized or automatic payment has been returned, reversed, or dishonoured as a result of an error on behalf of the bank/financial institution or the Company, the charge shall not apply.

7.1 SCHEDULE OF CHARGES

The following charges shall apply:

(a)	Connection or reconnection of electric service, whether metered or unmetered, to any premises during the Company's normal working hours.	$28.00 standard charge
(b)	Connection or reconnection of electric service, whether metered or unmetered, to any premises after the Company's normal working hours, if requested by the Customer and is not a reconnection for non payment.	$28.00 standard charge plus $75.00 charge for additional costs.
(c)	Reconnection of electric service, whether metered or unmetered, to any premises after the Company's normal working hours, if requested by the Customer and is a reconnection associated with non payment.	$28.00 standard charge plus $75.00 charge for additional costs.
(d)	Connection or reconnection of electric service to any premises serviced by temporary service in accordance with these Regulations.	$28.00 standard charge plus all other costs incurred by the Company in connecting or reconnecting service
(e)	Disconnection-Seasonal Electric Service	$30.00 standard charge
(f)	Returned Cheque Charge	$23.00
(g)	Interest on Overdue Accounts	1.5% per month or part thereof, or a maximum of 19.56% per annum
(h)	Interest on Deposits	Interest Rate based on Royal Bank prime rate minus 1%; set January 1st of each year

7.1 SCHEDULE OF CHARGES

(i)	Dispute Test Fee re satisfactory meter	$38.00
(j)	Standard Contribution for three-phase service 15 kW and under	$1,235.00
(k)	Charge for installation of Recording Equipment	
	• 240 volt single phase voltage recorder	$25.00
	• all other recording equipment	Actual Costs incurred by the Company
(l)	Service Charge for any miscellaneous requests.	Actual Costs incurred by the Company
(m)	All pole attachments for telecommunication common carriers, or broadcasters, exclusive of those under joint use agreements.	$14.15 per pole per year
(n)	Access to NSPI Mobile Radio Network	Monthly Charge
	- Basic Dispatch Service	$26.00
	- Individual/Group Call Feature	$21.00
	- Networking Features	$11.00
	- Interconnect Facility (PSTN) Access	$41.00

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.1 **Permits and Inspections**

Permits and inspections will normally be of three types:
a) Regular Permits and Inspections
b) Annual Permits and Inspections
c) Special Permits and Inspections

a) **Regular Permits and Inspections**

All persons, firms or corporations within Nova Scotia Power's inspection authority who are eligible to install electrical installations for the use of electrical energy shall, before commencing or doing any electrical installation of new equipment, or repairs, or altering or adding to any electrical installation or equipment already installed, submit and obtain approval in a manner prescribed by the inspection authority.

Individual permits shall be required for temporary and individual miscellaneous services and each dwelling unit of a single, duplex or row type housing, etc., whether supplied via an individual or multi-position metering devices.

Apartment type buildings, multi-tenant industrial and commercial installations shall be performed under one permit.

Permits are not transferable.

Permits shall be issued only to the firm or persons performing the work described on the Permit and in compliance with Section 4, "Permit" of the regulations made by the Fire Marshall pursuant to the Electrical Installation and Inspection Act.

Permit holders shall immediately notify the Electrical Inspection Authority upon the completion of an electrical installation requesting a FINAL inspection.

The fee for a Regular Permit and Inspection will be based on the Installed Value, including labour, material and sundries of the electrical installation, alteration, upgrade, repair or extension.

7.2 SCHEDULE OF WIRING INSPECTION FEES

When a dispute arises regarding the cost of an electrical installation the permit applicant may be required, at the Inspection Authority discretion, to supply a letter from the owner indicating the value of the contract and/or a bill of materials for the project.

The fees for a Regular Permit and Inspection, including the number of Inspection Visits, shall be based on the Installed Value of the installation as shown in the Inspection Fee Schedule.

b) **Annual Permits and Inspections**

An annual maintenance permit shall be issued for an establishment to cover all minor repairs as required under sections 4(a) (B), (2) and (3) of the regulations made by the Fire Marshal pursuant to the Electrical Installation Act.

Such a permit does not entitle the holder to effect major electrical alterations or additions.

The number of inspection visits shall be at the discretion of the Inspection Authority. Notwithstanding the above, at least one inspection visit shall be made in the year for which the permit is issued.

c) **Special Permits and Inspections**

Where the fee for a Regular Permit and Inspection are inappropriate the special permit and inspection fee shall apply. (Ex. carnivals and travelling shows).

7.2.2 **Late Application Fee**

Where an electrical contractor fails to obtain an electrical wiring permit prior to commencing the electrical work, an additional fee shall be payable in the amount of fifty (50) percent of the regular fee, up to a maximum additional fee of $100.00.

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.3 **Payment of Fees**

Fees for permits and inspections shall be paid at the time of requesting the permit unless otherwise indicated by the inspection authority. Permits having fees in arrears in excess of 120 days shall be subject to cancellation and at the discretion of the inspection authority, no additional permits shall be issued to the holder of the unpaid permits until such time the outstanding fees have been adequately dealt with.

7.2.4 **Refund of Fees**

The holder of a permit may apply to the inspection authority for a refund less a $10.00 non-refundable portion of the permit fee with respect to a cancelled or unused permit. No refund shall be issued for a permit where an inspection call has been made at the request of the permit holder.

7.2.5 **Expiry of Permits**

A permit for electrical work is valid for 12 months from the date of issue in respect of residential and 24 months in respect of all others unless otherwise noted on the permit. Upon expiry, a renewal fee to a maximum of 50% of the cost of the original permit shall be charged.

7.2.6 **Review of Plans and Specifications**

The Inspection Authority may, prior to issuing a permit, request the submission of plans and specifications for any proposed electrical installation. Plans shall be submitted for all commercial, industrial institutional installations exceeding 250 volts or 250 amperes.

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.7 **Inspection Fee Schedule**

a) **Regular Permits and Inspection**

The fee for a regular permit and the maximum number of inspection visits, with respect to an installation will be calculated, as follows.

b) **Annual Permit and Inspection**

The fee for an annual permit and inspection for any one establishment shall be the appropriate hourly rate.

c) **Special Permit and Inspection**

The fee for a special permit and inspection for any one project shall be the appropriate hourly rate.

d) **Plans Examination**

The fees for the examination of electrical plans and specifications shall be per review:

0 – 1,000 amps	$ 115.00
Greater than 1,000 amps	$ 115.00

e) **Primary Services**

The fees for the inspection of a primary service (padmount, vault, etc.) shall be per installation.	$124.00

f) **Letter of Acceptance**

The fees for a Letter of Acceptance shall be.............	$ 32.00

7.2 SCHEDULE OF WIRING INSPECTION FEES

INSPECTION FEE SCHEDULE

INSTALLED VALUE OF ELECTRICAL INSTALLATION	INSPECTION VISITS	PERMIT FEE
$ 0,000 to $ 2,000	1	$ 69.00
$ 2,001 to $ 4,000	2	$ 138.00
$ 4,001 to $ 6,000	2	$ 233.00
$ 6,001 to $ 8,000	2	$ 284.00
$ 8,001 to $ 10,000	2	$ 330.00
$ 10,001 to $ 15,000	3	$ 462.00
$ 15,001 to $ 25,000	3	$ 587.00
$ 25,001 to $ 50,000	3	$ 850.00
$ 50,001 to $ 100,000	3	$1,206.00
$100,001 to $ 300,000	4	$1,893.00
$300,001 to $ 500,000	5	$2,365.00
$500,001 to $750,000	6	$2,839.00
$750,001 to $1,000,000	8	$3,785.00
+ $1,000,000	10	$4,626.00 + 0.15% of cost in excess of $1,000,000

New Installations are subject to the following minimum inspection fees:

RESIDENTIAL-ALL INSTALLATIONS	$138.00
COMMERCIAL/INDUSTRIAL INSTITUTIONAL	
Up to 100 AMPS	$138.00
Over 100 to 400 AMPS	$330.00
Over 400 to 800 AMPS	$462.00
Over 800 to 1000 AMPS	$587.00
Over 1000 AMPS	$850.00

7.2 SCHEDULE OF WIRING INSPECTION FEES

g) **Hourly Rate Inspections**

Note: All fees are per inspection visit.

Normal Working Hours:

i)	For the first hour or fraction thereof	$ 68.00
ii)	For each additional half-hour or fraction thereof..	$ 28.00

Outside Normal Working Hours:

Extension of a regular work day (before or after)

i)	For the first hour or fraction thereof.......	$ 91.00
ii)	For each additional half-hour or fraction thereof..	$ 39.00

Weekends and Statutory Holidays:

Scheduled inspections on weekends (Saturday, Sunday) and statutory holidays:

i)	For the first hour or fraction thereof.......	$151.00
ii)	For each additional half-hour or fraction thereof..	$ 54.00

h) **Inspections in Excess of Maximum Number of Visits**

For an inspection visit, in excess of the maximum number of visits permitted under the Regular Permit and Inspection Fee the Special Permit and Inspection Fee shall apply.

7.3 SCHEDULE OF LOAD RESEARCH MONITORING, REPORTING AND ANALYTICAL CHARGES

The following schedule of charges shall apply to customers requesting Load Research information. **(Note: Customers must provide access to a shared phone line for data collection via automatic meter reading equipment):**

a) **Recovery of the Capital Cost of Installed Equipment** will be the actual costs incurred by the Company.

b) **Setup for Load Research** will be the actual cost incurred by Company plus a 25% markup.

c) **Analysis and Reporting Charges** will be the actual costs incurred by the Company plus at 25% markup.

d) **Specialized Customer Analysis** will be the actual costs incurred by the Company plus at 25% markup.

SCHEDULE OF LOAD RESEARCH CHARGES

		ONE TIME
1.0	**Recovery of Capital Cost of Meter Equipment**	The capital costs of metering equipment to be recovered will be the incremental cost of the AMR meter installed compared to an equivalent non-AMR meter.
2.0	**Recovery of Installation Charges**	When organizes and paid by NSPI, recovery of telephone line installation charges will be at cost.
	Single Phase Service Self-Contained	$44.00
	Single Phase Service, Transformer Rated and Three Phase Service	$119.00
3.0	**Recovery of Operational Charges**	$186.00
4.0	**Load Research Setup**	$47.00

7.3 SCHEDULE OF LOAD RESEARCH MONITORING, REPORTING AND ANALYTICAL CHARGES

5.0	**Analysis and Reporting**	**See Charge per Billing Period**
	Base Package	
	Load profile for peak day billing period plus times and magnitude of six highest peaks	33.00
	Options	
	Data File	33.00
	Load profile for each day for each billing period	33.00
	Power factor for plot for peak day (kVA billed cust. only)	33.00
	Power factor plot for each day (kVA billed cust. only)	11.00
	Reports of billing period average load profile for each day of the week	33.00
	Report of billing period average load profile for an specific day of the week	11.00
	Daily summary	11.00
	Monthly summary	11.00
	Weekly or monthly detail	11.00
	Daily comparison: Any two customers specified days	11.00
	Load duration plot	11.00
	Daily consumption plot	11.00
	Complete package (all of the above options)	180.00
6.0	**Specialized Analysis**	
	Hourly Rate	80.00

8.1 MERSEY SYSTEM

8.1.1 Delivery and Metering

The power and energy under this rate shall be metered, at the bus bars of the Mersey System Milton terminal station, and delivered, less losses, to customer substations.

8.1.2 Power Factor

The power factor of the customer's load shall not be lower than 95% lagging.

8.1.3 Billing

Bills shall be rendered monthly for 1/12 of the estimated charges for the current fiscal year under this rate.

Following the final fixing and apportionment of costs of the Mersey System, an adjustment account shall be rendered.

8.1.4 Other

Further conditions and operating rules may be desirable to optimize benefits of the Mersey System. Such conditions and rules, if approved by the Board, shall have the force and effect of regulations under this rate.

Amendments to the

Standard Generator Interconnection Procedures

for the Renewable to Retail Application.

Two revisions are proposed to this document for the Renewable to Retail Application:

Section 1: DEFINITIONS
A definition for Market Participant has been added.

Section 7.2: Execution of Interconnection System Impact Study Agreement
Subsection e has been added.

NOVA SCOTIA POWER
An Emera Company

STANDARD GENERATOR INTERCONNECTION PROCEDURES (GIP)

As Revised ●

(Applicable to Generating Facilities
Connected to or Impacting the Transmission System
at Voltages of 69 kV and above)

As approved by the UARB February 10, 2010

TABLE OF CONTENTS

SECTION 1. DEFINITIONS

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate - for the purposes of these Standard Generator Interconnection Procedures, the term "affiliate" shall be interpreted in accordance with Sections 2(2), 2(3), and 2(4) of the Nova Scotia Companies Act[1].

---

1 **Deemed affiliate**

2(2) A company shall be deemed to be an affiliate of another company if one of them is the subsidiary of the other or if both are subsidiaries of the same company or if each of them is controlled by the same person.

Deemed control

2(3) A company shall be deemed to be controlled by another person or by two or more companies if

(a) voting securities of the first-mentioned company carrying more than fifty per cent of the votes for the election of directors are held, otherwise than by way of security only, by or for the benefit of the other person or by or for the benefit of the other companies; and

(b) the votes carried by such securities are entitled, if exercised, to elect a majority of the directors of the first-mentioned company.

Deemed subsidiary

2(4) A company shall be deemed to be a subsidiary of another company if

(a) it is controlled by

(i) that other, or

(ii) that other and one or more companies each of which is controlled by that other, or

(iii) two or more companies each of which is controlled by that other; or

(b) it is a subsidiary of a company that is that other's subsidiary. R.S., c. 81, s. 2; 1990, c.15, s. 2.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, provincial and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the Northeast Power Coordinating Council or any successor thereto.

Applicable Reliability Standards shall mean the requirements and guidelines of the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected, and the NSPI Interconnection Guidelines and Standards as set out in Appendix D to this document.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Board shall mean the Nova Scotia Utility and Review Board.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Generator Interconnection and Operating Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Generator Interconnection and Operating Agreement.

Business Day shall mean Monday to Friday, inclusive, excluding holidays. The regular business hours on a Business Day are from 08:30 to 16:30 Atlantic Time.

Calendar Day shall mean any day including Saturday, Sunday or a holiday.

Commercial Operation Date shall mean the date on which Interconnection Customer commences commercial operation of the unit at the Generating Facility after Trial Operation of such unit has been completed as confirmed in writing substantially in the form shown in Appendix E of the Standard Generator Interconnection and Operating Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, as well as any information relating to a Party's technology, research and development, business affairs and pricing whether such information is supplied prior to or after the execution of the GIA which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electric system or group of systems that meet(s) the requirements of the NPCC Control Area Certification Process.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Generator Interconnection and Operating Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to distribute electricity to ultimate usage points such as homes and industries either directly from nearby generators or from interchanges from the Transmission System.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Generator Interconnection and Operating Agreement becomes effective in accordance with Article 2.1 of the Standard Generator Interconnection and Operating Agreement.

Emergency Condition shall mean a condition or situation:

(1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or

(2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or

(3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Standard Generator Interconnection and Operating Agreement to possess black start capability.

Energy Resource Interconnection Service (ER Interconnection Service) shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Force Majeure shall mean an event, condition, occurrence or circumstance beyond the reasonable control and not attributable to the fault or negligence of the Party claiming Force Majeure, which, despite all reasonable efforts at a reasonable cost of the Party claiming the Force Majeure to prevent its occurrence or mitigate its effects, causes a delay or disruption in the performance of any obligation (other than the obligation to pay monies due) imposed on such Party hereunder, including, without limitation, any act of God, labour disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment if caused by an event which would constitute Force Majeure, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control.

Generating Facility shall mean Interconnection Customer's device for the production of electricity for interconnection to the Transmission System at voltages 69 kV and above as identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean those practices, methods or acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America) that at a particular time, in the exercise of reasonable judgment, would have been expected to accomplish the desired result in a manner consistent with regulations, reliability, safety, environmental protection, economy and expedition as applied and practiced in the utility industry with respect to power generation, delivery, purchase and sale.

Governmental Authority shall mean any national, international, federal, provincial, state, municipal, county, regional or local government, organization or duly constituted authority having jurisdiction, and includes:

(a) any department, commission, bureau, board, administrative agency or regulatory body of any government having jurisdiction; and

(b) any person or corporation acting as an authorized agent thereof.

Grouped Study(ies) shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of “hazardous substances,” “hazardous wastes,” “hazardous materials,” “hazardous constituents,” “restricted hazardous materials,” “extremely hazardous substances,” “toxic substances,” “radioactive substances,” “contaminants,” “pollutants,” “toxic pollutants” or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially electrically connected to, and energized by, the Transmission System and upon which Trial Operation begins**.**

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Generator Interconnection and Operating Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System, and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission Provider's Transmission System. The scope of the study is defined in Section 8 of the Standard Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 6 of the Standard Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of (except for increases in capacity permitted by Section 2.6 of these Standard Generator Interconnection Procedures), or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Generator Interconnection and Operating Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Generator Interconnection Procedures.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Load Serving Entity shall mean one of the following:

(i) Nova Scotia Power Inc. (NSPI), or

(ii) a Nova Scotia municipal electric utility.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Generator Interconnection and Operating Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

Market Participant shall mean a person who has executed a Participation Agreement with the Nova Scotia Power System Operator (NSPSO), and Nova Scotia Power Inc. itself as specified in the Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules: Chapter 1.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Generator Interconnection and Operating Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

Network Resource shall mean that portion of a Generating Facility that is integrated with the Transmission Provider's Transmission System, designated as a Network Resource pursuant to the terms of the Tariff, and subjected to redispatch directives as ordered by the Transmission Provider in accordance with the Tariff.

Network Resource Interconnection Service (NR Interconnection Service) shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission Provider's Transmission System

(1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or

(2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources.

Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Customer interconnects to the Transmission Provider's Transmission System to accommodate the interconnection of the Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Generator Interconnection and Operating Agreement or its performance.

Operating Area shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Operating Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Generator Interconnection and Operating Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Progression Milestone(s) shall mean the prerequisite requirements required to enter the Interconnection System Impact Study stage, as itemized in Section 7.2.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is initially established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider, and as altered in accordance with Section 4.1 of the Standard Generator Interconnection Procedures.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Generator Interconnection and Operating Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Renewable Energy Standard shall have the meaning set out in Nova Scotia's Energy Standards Regulations or any successor legislation or regulations.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, exchanging information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, analyzing such information, and determining the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating:

(1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; or

(2) an option to purchase or acquire a leasehold site for the purpose of constructing the Generating Facility

Stand Alone Network Upgrades shall mean Network Upgrades that the Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Generator Interconnection and Operating Agreement.

Standard Generator Interconnection and Operating Agreement (GIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility, that is included in the Transmission Provider's Tariff.

Standard Small Generator Interconnection and Operating Agreement (SSGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility, that is interconnected to the Transmission Provider's Distribution System.

Standard Generator Interconnection Procedures (GIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility that are included in the Transmission Provider's Tariff.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect:

(1) the Transmission System from faults or other electrical disturbances occurring at the Generating Facility and

(2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission System or on other delivery systems or other generating systems to which the Transmission System is directly connected.

Tariff shall mean the Transmission Provider’s Tariff through which open access transmission service and Interconnection Service are offered, as filed with the Board, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Generator Interconnection and Operating Agreement to the extent necessary.

Transmission Provider shall mean Nova Scotia Power, Inc.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Generator Interconnection and

Operating Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to commercial operation.

SECTION 2. SCOPE AND APPLICATION

2.1 Application of Standard Generator Interconnection Procedures (GIP)

Sections 2 through 13 apply to processing an Interconnection Request pertaining to a Generating Facility. The GIP specifically applies when one of the following is proposed by an Interconnection Customer:

(i) a new Generating Facility at a new Point of Interconnection to the Transmission System, or interconnecting to the Distribution System when such interconnection is anticipated to impact the Transmission System, or

(ii) additional generation at an existing Point of Interconnection that does not meet the criteria set forth in Sections 2.6 (a) or (b), or

(iii) an increase in the capacity of an existing Generating Facility that does not meet the criteria set forth in Sections 2.6 (a) or (b).

2.2 Comparability

The Transmission Provider shall process and analyze all Interconnection Requests it receives in a timely manner as set forth in this GIP. The Transmission Provider will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by Transmission Provider, its subsidiaries or Affiliates or others.

2.3 Base Case Data

Transmission Provider shall provide base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list upon request subject to confidentiality provisions. Such databases and lists, hereinafter referred to as Base Cases, shall include all (i) generation projects and (ii) transmission projects, including merchant transmission projects that are proposed for the Transmission System for which a transmission expansion plan has been submitted and approved by the applicable authority.

2.4 No Applicability to Transmission Service

Nothing in this GIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

2.5 Expedited Process for Small Generating Facilities

In assessing whether the interconnection process can be expedited, the Transmission Provider will consider the capacity of the Generation Facility, the Point of Interconnection requested, and the results of any previously completed System Impact Studies that may be relevant.

To expedite the process, the Transmission Provider will consider the following options:

- Forego the Interconnection Feasibility Study
- Combine the Interconnection System Impact Study and the Interconnection Facilities Study
- Eliminate the requirement for coordination with Affected Systems
- Modify the Interconnection System Impact Study scope to exclude stability analysis.

2.6 Procedures for Assessment of Proposed Non-Material Additions or Modifications

For purposes of determining whether or not a proposed addition or modification to a generation facility is to be deemed a new Interconnection Request and therefore subject to the GIP, the following shall apply:

- Any proposed generation project addition is presumed by the Transmission Provider to be a new Interconnection Request and therefore subject to the requirements the GIP.
- The Generating Facility owner may request, in writing, that the Transmission Provider waive the requirement for submission of a new Interconnection Request

based on an assessment performed by the Transmission Provider of the impact of the proposed addition or modification on the Transmission System.

- The Transmission Provider will only assess requests that comply with the following:

  a) Project Size: Capacity increase up to 10 % of the aggregate Generating Facility capacity, and

  b) Point of Interconnection: The new request utilizes the Generating Facility's existing Point of Interconnection with the Transmission System.

- The cumulative increase of all previous additions made to an existing Generating Facility will be considered when assessing the size limit in a) above.
- Upon receipt of a request for assessment within the limits listed in a) and b) above, the Transmission Provider will consider potential system issues including: stability, voltage, power quality, thermal ratings and short circuit levels prior to waiving the requirement for a new Interconnection Request for the addition or modification.
- The Generating Facility shall provide additional technical information requested by the Transmission Provider.
- If in the sole judgment of the Transmission Provider the assessment of the addition or modification indicates no material impact, the requirement for a new Interconnection Request will be waived.
- The Transmission Provider shall use Reasonable Efforts to complete the assessment within thirty (30) Calendar Days.
- The Parties agree to subsequently amend the existing GIA, as applicable to reflect the addition of capacity or modification.

SECTION 3. INTERCONNECTION REQUESTS

3.1 General

An Interconnection Customer shall submit to the Transmission Provider an Interconnection Request in the form of Appendix 1 to this GIP and a refundable deposit of $15,000. The Transmission Provider shall apply the deposit toward the cost of an Interconnection Feasibility Study. The Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. The Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests.

At Interconnection Customer's option, Transmission Provider and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the Interconnection Feasibility Study Agreement.

3.2 Identification of Types of Interconnection Services

At the time the Interconnection Request is submitted, Interconnection Customer must request either Energy Resource (ER) Interconnection Service or Network Resource (NR) Interconnection Service, as described; provided, however, any Interconnection Customer requesting NR Interconnection Service may also request that it be concurrently studied as an ER Interconnection Service, up to the point when an Interconnection Facility Study Agreement is executed. Interconnection Customer may then elect to proceed with NR Interconnection Service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed.

3.2.1 Energy Resource Interconnection Service (ER Interconnection Service)

3.2.1.1 The Product

ER Interconnection Service allows Interconnection Customer to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. ER Interconnection Service does not in and of itself convey any transmission service.

3.2.1.2 The Study

The study consists of short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address short circuit issues associated with the Interconnection Facilities. The stability and steady state studies would identify necessary upgrades to allow full output of the proposed Generating Facility and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Generating Facility without requiring additional Network Upgrades.

3.2.2 Network Resource Interconnection Service (NR Interconnection Service)

3.2.2.1 The Product

The Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Generating Facility (1) in a manner comparable to that in which the Transmission Provider integrates its Generating Facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as Network Resources. NR Interconnection Service Allows the Interconnection Customer's Generating Facility to be designated as a Network Resource, up to the Generating Facility's full output, on the same basis as existing Network Resources interconnected to the Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur.

3.2.2.2 The Study

The Interconnection Study for NR Interconnection Service shall assure that the Interconnection Customer's Generating Facility meets the requirements for NR Interconnection Service and as a general matter, that such Generating Facility's interconnection is also studied with the Transmission Provider's Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on the Transmission Provider's Transmission System, consistent with the Transmission Provider's reliability criteria and procedures. This approach assumes that some portion of existing Network Resources are displaced by the output of the Interconnection Customer's Generating Facility. NR Interconnection Service in and of itself does not convey any transmission service. The Transmission Provider may also study the Transmission System under non-peak load conditions. However, upon request by the Interconnection Customer, the Transmission Provider must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

3.3 Valid Interconnection Request

3.3.1 Initiating an Interconnection Request

To initiate an Interconnection Request, Interconnection Customer must submit all of the following:

(i) a $15,000 deposit per Section 3.1;

(ii) a completed application in the form of Appendix 1;

(iii) demonstration of ownership of, a leasehold interest in, a right to develop, or an option to purchase or acquire an interest in a land area equal to at least 50% of that required for the purpose of constructing the Generating Facility proposed or a posting of an additional deposit of $20,000;

(iv) a defined Point of Interconnection; and

(v) a one-line diagram of the Generating Facility showing the proposed Interconnection Facilities and the Point of Interconnection.

The deposit provided pursuant to item (i) may, at the Interconnection Customer's option, be delivered by way of a certified cheque or bank draft.

Any deposit provided pursuant to item (iii) shall be applied toward any Interconnection Studies pursuant to the Interconnection Request. Any deposit provided pursuant to item (iii) of this Section shall be refundable if the Interconnection Customer demonstrates ownership of, a leasehold interest in, a right to develop, or an option to purchase or acquire a land area equal to at least 50% of that required for the purpose of constructing the Generating Facility proposed no later than ten (10) Business Days after start date of the Interconnection System Impact Study or upon withdrawal of the Interconnection Request by either the Interconnection Customer or Transmission Provider before entry into the

Interconnection System Impact Study stage; otherwise, all such deposit(s), additional and initial, become non-refundable.

The expected In-Service Date of the new Generating Facility or increase in capacity of the existing Generating Facility shall be no more than the process window for the regional expansion planning period (or in the absence of a regional planning process, the process window for the Transmission Provider's expansion planning period) not to exceed seven (7) years from the date the Interconnection Request is received by the Transmission Provider, unless the Interconnection Customer demonstrates that engineering, permitting and construction of the new Generating Facility or increase in capacity of the existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by the Transmission Provider by a period up to ten (10) years or longer where the Interconnection Customer and Transmission Provider agree, such agreement not to be unreasonably withheld.

3.3.2 Acknowledgment of Interconnection Request

Transmission Provider shall acknowledge receipt of the Interconnection Request within five (5) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement.

3.3.3 Deficiencies in Interconnection Request

An Interconnection Request will not be considered to be a valid request until all items in Section 3.3.1 have been received by the Transmission Provider. If an Interconnection Request fails to meet the requirements set forth in Section 3.3.1, the Transmission Provider shall notify the Interconnection Customer within five (5) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. Interconnection Customer shall provide the Transmission Provider the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by Interconnection Customer to comply with this Section 3.3.3 shall be treated in accordance with Section 3.6.

3.3.4 Scoping Meeting

Within ten (10) Business Days after receipt of a valid Interconnection Request, Transmission Provider shall establish a date agreeable to Interconnection Customer for the Scoping Meeting, and such date shall be no later than 30 Calendar Days from receipt of the valid Interconnection Request, unless otherwise mutually agreed upon by the Parties.

The purpose of the Scoping Meeting shall be to discuss alternative interconnection options, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection. Transmission Provider and Interconnection Customer will bring to the meeting such technical data, including, but not limited to:

(i) general facility loadings,
(ii) general instability issues,
(iii) general short circuit issues,
(iv) general voltage issues, and
(v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting.

Transmission Provider and Interconnection Customer will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer shall designate its Point of Interconnection, pursuant to Section 6.1, and one or more available alternative Point(s) of

Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose.

3.4 OASIS Posting

The Transmission Provider will maintain on its OASIS a list of all valid Interconnection Requests. The list will identify, for each Interconnection Request:

(i) the maximum summer and winter megawatt electrical output;

(ii) the location by county;

(iii) the station or transmission line or lines where the interconnection will be made;

(iv) the projected In-Service Date;

(v) the status of the Interconnection Request, including Queue Position;

(vi) the type of Interconnection Service being requested; and

(vii) the availability of any studies related to the Interconnection Request;

(viii) the date of the Interconnection Request;

(ix) the type of Generating Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); and

(x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed.

Except in the case of an Affiliate of the Transmission Provider, the list will not disclose the identity of the Interconnection Customer until the Interconnection Customer executes a GIA or requests that the Transmission Provider file an unexecuted GIA with the Board. The Transmission Provider shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to the Transmission Provider's OASIS site subsequent to the meeting between the Interconnection Customer and the Transmission Provider to discuss the applicable study results. The Transmission Provider shall also post any known deviations in the Generating Facility's In-Service Date.

3.5 Coordination with Affected Systems

The Transmission Provider will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators and, if possible, include those results in its applicable Interconnection Study within the time frame specified in this GIP. The Transmission Provider will include such Affected System Operators in all meetings held with the Interconnection Customer as required by this GIP. The Interconnection Customer will cooperate with the Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider, which may be an Affected System, shall cooperate with the Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

3.6 Withdrawal

The Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to the Transmission Provider. In addition, if the Interconnection Customer fails to adhere to all requirements of this GIP, except as provided in Section 13.5 (Disputes), the Transmission Provider shall deem the Interconnection Request to be withdrawn and shall provide written notice to the Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, the Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify the Transmission Provider of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of the Interconnection Customer’s Queue Position. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during Dispute Resolution, the Interconnection Customer's Interconnection Request is eliminated from the queue until such time that the outcome of Dispute Resolution would restore its Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to the Transmission Provider all costs that the Transmission Provider prudently incurs with respect to that Interconnection Request prior to the Transmission Provider's receipt of notice described above and, if such withdrawal occurs following the expiration of the transition periods specified in Section 5.1, all costs associated with subsequent re-studies of lower queued projects deemed necessary by the Transmission Provider as a result of the withdrawal of the Interconnection Request. Upon withdrawal, the Transmission Provider shall retain all deposits previously provided by the Interconnection Customer with respect to the Interconnection Request, to be applied towards costs incurred by the Transmission Provider, to conduct re-studies of lower queued projects deemed necessary as a result of the withdrawal of the Interconnection Request. The withdrawn Interconnection Customer shall pay to the Transmission Provider all re-study costs that exceed the deposits previously provided. If the Transmission Provider, using Reasonable Efforts, is unable to obtain payment from the withdrawn Interconnection Customer, it shall charge the applicable lower-queued Interconnection Customer the re-study costs incurred with respect to that Interconnection Request that are in excess of the deposit amount.

If an Interconnection Customer withdraws its Interconnection Request within 30 days following the effective date of these revised Standard Generator Interconnection Procedures, the withdrawing Interconnection Customer shall not be responsible for any costs of re-studies of lower queued Interconnection Requests deemed necessary by the Transmission Provider as a result of the withdrawal of the Interconnection Request and instead the Interconnection Customer of the applicable lower-queued Interconnection Request or Requests shall be so responsible.

The Interconnection Customer must pay all monies due to the Transmission Provider before it is allowed to obtain any Interconnection Study data or results.

The Transmission Provider shall

(i) update the OASIS Queue Position posting; and

(ii) refund to the Interconnection Customer any portion of the Interconnection Customer's deposits, study or re-study payments that exceed the costs that the Transmission Provider has incurred, including interest. Any applicable refund will be made upon completion of all required re-studies, or upon the determination by the Transmission Provider that there are no material impacts to lower-queued Interconnection Requests as a result of such withdrawal. In the event of such withdrawal, the Transmission Provider, subject to the confidentiality provisions of Section 13.1, shall provide, at Interconnection Customer's request, all information that the Transmission Provider developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

SECTION 4. QUEUE POSITION

4.1 General

The Transmission Provider shall assign an initial Queue Position based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and the Interconnection Customer provides such information in accordance with Section 3.3.3, then the Transmission Provider shall assign the Interconnection Customer a Queue Position based on the date the application form was originally filed. Moving a Point of Interconnection shall result in a lowering of Queue Position if it is deemed a Material Modification under Section 4.4.3.

The initial Queue Position of each Interconnection Request will be used to determine the order of performing the Interconnection Feasibility Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request except in the case of common facilities required for two or more Interconnection Requests examined together under a Grouped Study. A higher queued Interconnection Request is one that has been placed "earlier" in the queue in relation to another Interconnection Request that is lower queued.

The initial Queue Position shall be reassigned for an Interconnection Request as it proceeds through the Generator Interconnection Procedures under the following circumstance which allows lower queued requests to advance in the queue order:

(i) the Interconnection Customer demonstrates to the Transmission Provider that, at any time following completion of the Interconnection Feasibility Study, all required Progression Milestones for the Interconnection System Impact Study stage have been met for the respective Interconnection Request prior to the Interconnection System Impact Study stage commencement date established in advance by the Transmission Provider.

The resulting Queue Position is based on the date and time of the demonstration of achievement of the final Interconnection System Impact Study stage Progression Milestone for the Interconnection Request by the Interconnection Customer, and a prioritized Queue Position is established on this basis.

Should the Interconnection Request not proceed to the Interconnection System Impact Study stage within two (2) years from i) the date of the valid Interconnection Request or ii) the effective date of this revised GIP, whichever is the later, the Transmission Provider shall deem the Interconnection Request to be withdrawn.

4.2 Study Grouping

At Transmission Provider's option, Interconnection Requests may be studied serially or in groups for the purpose of the Interconnection System Impact Study.

Grouping shall be implemented on the basis of Queue Position, except when a particular Interconnection Request is sufficiently electrically remote from others that it cannot reasonably be grouped with other Interconnection Requests. At the discretion of the Transmission Provider, requests may be studied together without regard to the nature of the underlying Interconnection Service, whether ER Interconnection Service or NR Interconnection Service. Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Generating Facility.

Grouped Interconnection System Impact Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the Transmission System's capabilities at the time of each study.

4.3 Transferability of Queue Position

An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change.

4.4 Modifications

The Interconnection Customer shall submit to the Transmission Provider, in writing, modifications to any information provided in the Interconnection Request. The Interconnection Customer shall retain its Queue Position if the modifications are in accordance with Sections 4.4.1, 4.4.2 or 4.4.5, or are determined not to be Material Modifications pursuant to Section 4.4.3.

Notwithstanding the above, during the course of the Interconnection Studies, either the Interconnection Customer or Transmission Provider may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to the Transmission Provider and Interconnection Customer, such acceptance not to be unreasonably withheld, Transmission Provider shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 6.4, Section 7.6 and Section 8.5 as applicable and Interconnection Customer shall retain its Queue Position.

4.4.1 Prior to the return of the executed Interconnection System Impact Study Agreement to the Transmission Provider, modifications permitted under this Section shall include specifically:

(a) a reduction up to 60 percent (MW) of electrical output of the proposed project as submitted in the original Interconnection Request;

(b) modifying the technical parameters associated with the Generating Facility technology or the Generating Facility step-up transformer impedance characteristics; and

(c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of cost allocation and study analysis.

4.4.2 Prior to the return of the executed Interconnection Facility Study Agreement to the Transmission Provider, the modifications permitted under this Section shall include specifically:

(a) additional 15 percent decrease in plant size (MW) from the amount identified in Section 7.2 (v), and

(b) Generating Facility technical parameters associated with modifications to Generating Facility technology and transformer impedances; provided, however, the incremental costs associated with those modifications are the responsibility of the requesting Interconnection Customer.

4.4.3 Prior to making any modification other than those specifically permitted by Sections 4.4.1, 4.4.2, and 4.4.5, Interconnection Customer may first request that the Transmission Provider evaluate whether such modification is a Material Modification. In response to Interconnection Customer's request, the Transmission Provider shall evaluate the proposed modifications prior to making them and inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection shall constitute a Material Modification. The Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

4.4.4 Upon receipt of Interconnection Customer's request for modification permitted under this Section 4.4, the Transmission Provider shall commence and perform any necessary additional studies as soon as practicable, but in no event shall the Transmission Provider commence such studies later than 30 Calendar Days after receiving notice of Interconnection Customer's request. Any additional studies resulting from such modification shall be done at Interconnection Customer's cost.

4.4.5 Extensions of less than three (3) cumulative years in the Commercial Operation Date of the Generating Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing.

SECTION 5. TRANSITION PROCEDURES FOR INTERCONNECTION REQUESTS SUBMITTED PRIOR TO EFFECTIVE DATE OF THE REVISED STANDARD GENERATOR INTERCONNECTION PROCEDURES.

5.1 Transition Requirements

5.1.1 Any Interconnection Customer assigned a Queue Position prior to the effective date of this revised GIP shall retain that Queue Position, provided they meet the requirements of this Section 5.1. Any Interconnection Customer that fails to meet these requirements shall have its Interconnection Request deemed withdrawn pursuant to Section 3.6.

5.1.1.1 All Interconnection Requests for which Interconnection Facilities Study Agreements have been executed and deposits provided prior to the effective date of this revised GIP, including those with Facilities Studies in progress and in Generator Interconnection Agreement negotiation, will not be required to conform with the deposits and requirements of Section 8.1 of this revised GIP.

5.1.1.2 Interconnection Requests that have an executed Interconnection System Impact Study Agreement prior to the effective date of this revised GIP will be required to conform fully to the requirements of Section 7.2 of this revised GIP prior to entry to the Interconnection System Impact Study stage. This applies to Interconnection Requests which, on the effective date of this revised GIP, have an Interconnection System Impact Study in progress and those for which the Interconnection System Impact Study has not been started.

5.1.1.3 Interconnection Requests that have an executed Interconnection Feasibility Study Agreement prior to the effective date of this revised GIP will be required to conform to the requirements of Section 6.1 prior to commencement or re-commencement of the Interconnection Feasibility Study. This applies to Interconnection Requests which, on the effective date of this revised GIP, have an Interconnection Feasibility Study in progress and those for which the Interconnection Feasibility Study has not been started. Within thirty (30) Calendar Days after the effective date of this revised GIP, such Interconnection Requests shall be revised and re-submitted by the Interconnection Customer in conformance with all deposits and data requirements of Section 3.3.1 of this revised GIP.

5.1.1.4 All Interconnection Requests that have not executed either an Interconnection Feasibility Study Agreement or an Interconnection System Impact Study Agreement prior to the effective date of this revised GIP will be required to conform fully to the requirements of this revised GIP. Within thirty (30) Calendar Days after the effective date of this revised GIP, such Interconnection Requests shall be revised and re-submitted by the Interconnection Customer in conformance with all deposit and data requirements of Section 3.3.1 of this revised GIP.

5.2 New Transmission Provider

If the Transmission Provider transfers control of its Transmission System to a successor Transmission Provider during the period when an Interconnection Request is pending, the original Transmission Provider shall transfer to the successor Transmission Provider any amount of the deposit or payment with interest thereon that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net amount and the deposit or payment required by this GIP shall be paid by or refunded to the Interconnection Customer, as appropriate. The original Transmission Provider shall coordinate with the successor Transmission Provider to complete any Interconnection Study, as appropriate, that the original Transmission Provider has begun but has not completed. If the Transmission Provider has tendered a draft GIA to the Interconnection Customer but the Interconnection

Customer has not executed the GIA or requested the filing of an unexecuted GIA with the Board, unless otherwise provided, the Interconnection Customer may elect to complete negotiations with the Transmission Provider or the successor Transmission Provider.

SECTION 6. INTERCONNECTION FEASIBILITY STUDY

6.1 Interconnection Feasibility Study Agreement

Simultaneously with the acknowledgement of a valid Interconnection Request the Transmission Provider shall provide to Interconnection Customer an Interconnection Feasibility Study Agreement in the form of Appendix 2. The Interconnection Feasibility Study Agreement shall specify that Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study. Within five (5) Business Days following the Scoping Meeting Interconnection Customer shall specify for inclusion in the attachment to the Interconnection Feasibility Study Agreement the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection. Within five (5) Business Days following the Transmission Provider's receipt of such designation, Transmission Provider shall tender to Interconnection Customer two copies of the Interconnection Feasibility Study Agreement, which includes a good faith estimate of the cost for completing the Interconnection Feasibility Study. The Interconnection Customer shall execute and deliver to the Transmission Provider the Interconnection Feasibility Study Agreement no later than 30 Calendar Days after its receipt. The Transmission Provider shall execute the Interconnection Feasibility Study Agreement and deliver a fully executed copy to the Interconnection Customer.

On or before the return of the executed Interconnection Feasibility Study Agreement to the Transmission Provider, the Interconnection Customer shall provide the technical data called for in Appendix 1, Attachment A.

If the Interconnection Feasibility Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and Re-studies shall be completed pursuant to Section 6.4 as applicable. For the purpose of this Section 6.1, if the

Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.3.4, shall be the substitute.

If Interconnection Customer and Transmission Provider agree to forgo the Interconnection Feasibility Study, Transmission Provider will initiate an Interconnection System Impact Study under Section 7 of this GIP and apply the $15,000 deposit towards the Interconnection System Impact Study.

6.2 Scope of Interconnection Feasibility Study

The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Transmission System.

The Interconnection Feasibility Study will consider the Base Case as well as all Generating Facilities (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the Transmission System or Distribution System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request, to the extent their studies are completed; (iii) have established a pending higher queued Interconnection Request to interconnect to the Transmission System by virtue of having met the required Interconnection System Impact Study stage Progression Milestones listed in Section 7.2 or the Interconnection Facilities Study requirements of Section 8.1; and iv) have no Queue Position but have executed a GIA (or a Standard Small Generator Interconnection Agreement) or requested that an unexecuted GIA be filed with the Board. The Interconnection Feasibility Study will consist of a power flow and short circuit analysis. The Interconnection Feasibility Study will provide a list of facilities and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

6.3 Interconnection Feasibility Study Procedures

The Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. The Transmission Provider shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than forty-five (45) Calendar Days after the Transmission Provider receives the fully executed Interconnection Feasibility Study Agreement. At the request of the Interconnection Customer or at any time the Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, Transmission Provider shall notify the Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If the Transmission Provider is unable to complete the Interconnection Feasibility Study within that time period, it shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, the Transmission Provider shall provide the Interconnection Customer supporting documentation, workpapers and relevant power flow, short circuit and stability databases for the Interconnection Feasibility Study, subject to confidentiality arrangements consistent with Section 13.1.

6.3.1 Meeting with Transmission Provider

Within ten (10) Business Days of providing an Interconnection Feasibility Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Feasibility Study.

6.4 Re-Study

If re-study of the Interconnection Feasibility Study is required due to a higher queued project, which has established a pending higher queued Interconnection Request to interconnect to the Transmission System by virtue of having met the required Interconnection System Impact Study stage Progression Milestones listed in Section 7.2 or the Interconnection Facilities Study requirements of Section 8.1, dropping out of the queue, or a modification of such higher queued project subject to Section 4.4, Transmission Provider shall notify Interconnection Customer in writing. Such re-study shall take not longer than forty-five (45) Calendar Days from the date of the notice.

An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request per Section 3.6, modifies its Interconnection Request subject to Section 4.4, or re-designates the Point of Interconnection pursuant to Section 6.1 shall pay to the Transmission Provider all costs that the Transmission Provider prudently incurs with respect to subsequent re-studies of the Interconnection Customer's Interconnection Request deemed necessary by the Transmission Provider due to these events. The Transmission Provider shall retain all applicable deposits previously provided by the Interconnection Customer with respect to the Interconnection Request, to be applied towards costs incurred by the Transmission Provider, to conduct the re-studies it deems necessary. The Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request per Section 3.6, modifies its Interconnection Request subject to Section 4.4, or re-designates the Point of Interconnection pursuant to Section 6.1, shall also pay to the Transmission Provider any re-study cost amounts that exceed the deposits previously provided.

SECTION 7. INTERCONNECTION SYSTEM IMPACT STUDY

7.1 Interconnection System Impact Study Agreement

Unless otherwise agreed, pursuant to the Scoping Meeting provided in Section 3.3.4, simultaneously with the delivery of the Interconnection Feasibility Study to the Interconnection Customer, the Transmission Provider shall provide to the Interconnection Customer an Interconnection System Impact Study Agreement in the form of Appendix 3 to this GIP. The Interconnection System Impact Study Agreement shall provide that the Interconnection Customer shall compensate the Transmission Provider for the actual cost of the Interconnection System Impact Study. Within three (3) Business Days following the Interconnection Feasibility Study results meeting, the Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection System Impact Study.

7.2 Execution of Interconnection System Impact Study Agreement

The Interconnection Customer shall execute two copies of the Interconnection System Impact Study Agreement and deliver both copies of the executed Interconnection System Impact Study Agreement to the Transmission Provider no later than 30 Calendar Days after its receipt along with deposits in the amount listed as follows:

Project Capacity:	SIS Deposit plus	Re-Study Deposit
Does not exceed 20 MW:	$ 50,000	$100,000
Exceeds 20 MW but does not exceed 50MW:	$ 75,000	$150,000
Exceeds 50 MW but does not exceed 150MW:	$100,000	$200,000
Exceeds 150 MW:	$150,000	$300,000

The Interconnection System Impact Study deposit may, at the Interconnection Customer's option, be delivered by way of a certified cheque or bank draft. The associated re-study deposit may, at the Interconnection Customer's option, be delivered by way of a certified cheque or bank draft or by way of a letter of credit or some other form of security reasonably acceptable to the Transmission Provider; provided, however, that any such letter of credit or security must be in a form and issued by a party reasonably acceptable to the Transmission Provider and consistent with the applicable laws of Nova Scotia.

The Transmission Provider shall execute the Interconnection System Impact Study Agreement and deliver a fully executed copy to the Interconnection Customer.

To be eligible for inclusion in the Interconnection System Impact Study stage, and thereby advance the Interconnection Request's initial Queue Position, the following designated Progression Milestones must be met by the Interconnection Customer at least ten (10) Business Days prior to the Interconnection System Impact Study commencement date:

(i) provision of a detailed stability model for the generator(s)

(ii) provision of a completed Attachment A to Appendix 1;

(iii) confirmation of the Point of Interconnection;

(iv) provision of a one-line diagram showing the Generating Facility and associated electrical equipment with appropriate rating and impedance information;

(v) confirmation of generation MW output;

(vi) re-validation of Site Control provided in accordance with Section 3.3.1, provided further that, if Interconnection Customer provided $20,000 deposit in-lieu of Site Control with Interconnection Request then the deposit becomes non-refundable ten (10) Business Days after the start date of the Interconnection System Impact Study stage; and

(vii) any one of the following at the Interconnection Customer's discretion:

a. confirmation of the existence of an executed contract for sale of energy from the generating facility for at least 50% of the generation project capability;

b. confirmation of a long-term transmission service reservation made with a duration of at least one (1) year, for at least 50% of the project capacity, held by the Interconnection Customer directly or under contract with another Nova Scotia Market Participant that holds the transmission reservation;

c. demonstration of approval by the Nova Scotia Utility and Review Board for the expenditures necessary for the Generating Facility; ~~or~~

d. demonstration by a Load Serving Entity that the project's energy or capacity has been identified as required to meet demand, reliability or Renewable Energy Standard requirements; or

~~d.~~e. demonstration by the Interconnection Customer to the satisfaction of the Transmission Provider that the Interconnection Customer is a retail supplier pursuant to the *Electricity Act*, S.N.S 2004, c. 25.

If the Interconnection Customer does not provide all required technical data when it delivers the Interconnection System Impact Study Agreement, the Transmission Provider shall notify the Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection System Impact Study Agreement and the Interconnection Customer shall cure the deficiency within five (5) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Interconnection System Impact Study Agreement or deposit, or demonstration of Progression Milestone achievement.

If the Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting and the Interconnection Feasibility Study, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and restudies shall be completed pursuant to Section 7.6 as applicable. For the purpose of this Section 7.2, if the Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.3.4, shall be the substitute.

Upon receipt of the Interconnection System Impact Study, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection System Impact Study.

7.3 Scope of Interconnection System Impact Study

The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The Interconnection System Impact Study will consider the Base Case as well as all Generating Facilities (and with respect to (iii) and (iv) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced:

(i) are directly interconnected to the Transmission System or Distribution System;

(ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request, to the extent their studies are completed;

(iii) have established a pending higher queued Interconnection Request to interconnect to the Transmission System by virtue of: a) having met the required Interconnection System Impact Study stage Progression Milestones listed in Section 7.2 or the Interconnection Facilities Study requirements of Section 8.1; or b) transitioning per Section 5.1.1.1; and

(iv) have executed or are negotiating a GIA (or a Standard Small Generator Interconnection Agreement) or have requested that an unexecuted GIA be filed with the Board.

The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The Interconnection System Impact Study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Interconnection System Impact Study will provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

7.4 Interconnection System Impact Study Procedures

The Transmission Provider shall coordinate the Interconnection System Impact Study with any Affected System that is affected by the Interconnection Request pursuant to Section 3.5 above. The Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. The Transmission Provider shall use Reasonable Efforts to complete the Interconnection System Impact Study within 120 Calendar Days after Interconnection System Impact Study commencement date.

At the request of the Interconnection Customer or at any time the Transmission Provider determines that it will not meet the required time frame for completing the Interconnection System Impact Study, Transmission Provider shall notify the Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If the Transmission Provider is unable to complete the Interconnection System Impact Study within the time period, it shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Interconnection System Impact Studies that are not completed by the end of the 120 calendar day study period will continue and will retain their Queue position within the subsequent study group. Upon request, the Transmission Provider shall provide the Interconnection Customer all supporting documentation, workpapers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the Interconnection System Impact Study, subject to confidentiality arrangements consistent with Section 13.1.

The Transmission Provider will post to its OASIS, an annual calendar showing the planned commencement dates for Interconnection System Impact Study groups.

7.5 Meeting with Transmission Provider

Within ten (10) Business Days of providing an Interconnection System Impact Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection System Impact Study.

7.6 Re-Study

If re-study of the Interconnection System Impact Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to 4.4, or re-designation of the Point of Interconnection pursuant to Section 7.2 Transmission Provider shall notify Interconnection Customer in writing. Such re-study shall take no longer than sixty (60) Calendar Days from the date of notice.

An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request per Section 3.6, modifies its Interconnection Request subject to Section 4.4, or re-designates the Point of Interconnection pursuant to Section 7.2 shall pay to the Transmission Provider all costs that the Transmission Provider prudently incurs with respect to subsequent re-studies of the Interconnection Customer's or any lower-queued Interconnection Request deemed necessary by the Transmission Provider due to these events. The Transmission Provider shall retain all applicable deposits previously provided by the Interconnection Customer with respect to the Interconnection Request, to be applied towards costs incurred by the Transmission Provider, to conduct the re-studies it deems necessary. The Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request per Section 3.6, modifies its Interconnection Request subject to Section 4.4, or re-designates the Point of Interconnection pursuant to Section 7.2, shall also pay to the Transmission Provider any re-study cost amounts that exceed the deposits previously provided. If the Transmission Provider, using Reasonable Efforts, is unable to obtain payment from the Interconnection Customer, it shall charge the lower-queued, re-studied Interconnection Customer the re-study costs incurred with respect to that Interconnection Request that are in excess of the deposit amount held by the Transmission Provider.

SECTION 8. INTERCONNECTION FACILITIES STUDY

8.1 Interconnection Facilities Study Agreement

Simultaneously with the delivery of the Interconnection System Impact Study to the Interconnection Customer, the Transmission Provider shall provide to the Interconnection Customer an Interconnection Facilities Study Agreement in the form of Appendix 4 to this GIP. The Interconnection Facilities Study Agreement shall provide that the Interconnection Customer shall compensate the Transmission Provider for the actual cost of the Interconnection Facilities Study. Within three (3) Business Days following the Interconnection System Impact Study results meeting, the Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection Facilities Study. The Interconnection Customer shall execute two copies of the Interconnection Facilities Study Agreement and deliver both copies of the executed Interconnection Facilities Study Agreement to the Transmission Provider within 30 Calendar Days after its receipt, together with the required technical data, confirmation of the definitive generation MW output and deposits in the amount listed as follows:

Project Capacity:	**Facilities Study Deposit** plus	**Re-Study Deposit**
Does not exceed 20 MW:	$ 25,000	$25,000
Exceeds 20 MW but does not exceed 150MW:	$50,000	$50,000
Exceeds 150 MW:	$75,000	$75,000

The Interconnection Facilities Study deposit may, at the Interconnection Customer's option, be delivered by way of a certified cheque or bank draft. The associated re-study deposit may, at the Interconnection Customer's option, be delivered by way of a certified cheque or bank draft or by way of a letter of credit or some other form of security reasonably acceptable to the Transmission Provider; provided, however, that any such letter of credit or security must be in a form and issued by a party reasonably acceptable to the Transmission Provider and consistent with the applicable laws of Nova Scotia.

The Transmission Provider shall execute the Interconnection Facilities Study Agreement and deliver a fully executed copy to the Interconnection Customer.

8.1.1 Upon receipt of the Interconnection Facilities Study, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Facilities Study.

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to the Interconnection Customer, as appropriate.

8.2 Scope of Interconnection Facilities Study

The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facility to the Transmission System. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Transmission Provider's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

8.3 Interconnection Facilities Study Procedures

The Transmission Provider shall coordinate the Interconnection Facilities Study with any Affected System pursuant to Section 3.5 above. The Transmission Provider shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study. The Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to the Interconnection Customer within 120 days, with a +/- 10 percent cost estimate, after the receipt of the Interconnection System

Impact Study Agreement, study deposits, all required technical data, and confirmation of the definitive generation MW output.

At the request of the Interconnection Customer or at any time the Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Facilities Study, Transmission Provider shall notify the Interconnection Customer as to the schedule status of the Interconnection Facilities Study. If the Transmission Provider is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study report within the time required, it shall notify the Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

The Interconnection Customer may, within 30 Calendar Days after receipt of the draft report, provide written comments to the Transmission Provider, which the Transmission Provider shall include in the final report. The Transmission Provider shall issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving the Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. The Transmission Provider may reasonably extend such fifteen-day period upon notice to the Interconnection Customer if the Interconnection Customer's comments require the Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. Upon request, the Transmission Provider shall provide the Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 13.1.

8.4 Meeting with Transmission Provider

Within ten (10) Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study.

8.5 Re-Study

If re-study of the Interconnection Facilities Study is required due to a higher queued project dropping out of the queue or a modification of a higher queued project pursuant to Section 4.4, Transmission Provider shall so notify Interconnection Customer in writing. Such re-study shall take no longer than sixty (60) Calendar Days from the date of notice.

An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request per Section 3.6 or modifies its Interconnection Request subject to Section 4.4 shall pay to the Transmission Provider all costs that the Transmission Provider prudently incurs with respect to subsequent re-studies of the Interconnection Customer's or any lower-queued Interconnection Request deemed necessary by the Transmission Provider due to these events. The Transmission Provider shall retain all applicable deposits previously provided by the Interconnection Customer with respect to the Interconnection Request, to be applied towards costs incurred by the Transmission Provider, to conduct the re-studies it deems necessary. The Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request per Section 3.6 or modifies its Interconnection Request subject to Section 4.4 shall also pay to the Transmission Provider any re-study cost amounts that exceed the deposits previously provided. If the Transmission Provider, using Reasonable Efforts, is unable to obtain payment from the Interconnection Customer, it shall charge the lower-queued, re-studied Interconnection Customer the re-study costs incurred with respect to that Interconnection Request that are in excess of the deposit amount held by the Transmission Provider.

SECTION 9. ENGINEERING & PROCUREMENT (E&P) AGREEMENT

Prior to executing a GIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request and Transmission Provider shall offer the Interconnection Customer, an E&P Agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, the Transmission Provider shall not be obligated to offer an E&P Agreement if Interconnection Customer is in Dispute Resolution as a result of an allegation that Interconnection Customer has failed to meet any milestones or comply with any prerequisites specified in other parts of the GIP. The E&P Agreement is an optional procedure and it will not alter the Interconnection Customer's Queue Position or In-Service Date. The E&P Agreement shall provide for the Interconnection Customer to pay the cost of all activities authorized by the Interconnection Customer and to make advance payments or provide other satisfactory security for such costs.

The Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If Interconnection Customer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, Transmission Provider may elect:

(i) to take title to the equipment, in which event Transmission Provider shall refund Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment, or

(ii) to transfer title to and deliver such equipment to Interconnection Customer, in which event Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.

SECTION 10. OPTIONAL INTERCONNECTION STUDY

10.1 Optional Interconnection Study Agreement

At any time after completion of the Interconnection Feasibility Study, or upon agreement to forego the Interconnection Feasibility Study in accordance with Section 6.1, the Interconnection Customer may request, and the Transmission Provider shall perform a reasonable number of Optional Studies. The request shall describe the assumptions that the Interconnection Customer wishes the Transmission Provider to study within the scope described in Section 10.2. Within ten (10) Business Days after receipt of a request for an Optional Interconnection Study, the Transmission Provider shall provide to the Interconnection Customer an Optional Interconnection Study Agreement in the form of Appendix 5.

The Optional Interconnection Study Agreement shall:

(i) specify the technical data that the Interconnection Customer must provide for each stage of the Optional Interconnection Study,

(ii) specify Interconnection Customer's assumptions as to which Interconnection Requests with earlier queue priority dates will be excluded from the Optional Interconnection Study case and assumptions as to the type of interconnection service for Interconnection Requests remaining in the Optional Interconnection Study case, and

(iii) provide the Transmission Provider's estimate of the cost of the Optional Interconnection Study.

To the extent known by the Transmission Provider, such estimate shall include any costs expected to be incurred by any Affected System whose participation is necessary to complete the Optional Interconnection Study. Notwithstanding the above, the Transmission Provider shall not be required as a result of an Optional Interconnection Study request to conduct any additional Interconnection Studies or delay the completion of Interconnection Studies with respect to any other Interconnection Request.

The Interconnection Customer shall execute two copies of the Optional Interconnection Study Agreement within ten (10) Business Days of receipt and deliver both copies of the Optional Interconnection Study Agreement, the technical data and a $50,000 deposit to the Transmission Provider.

The deposit may, at the Interconnection Customer's option, be delivered by way of a certified cheque or bank draft.

The Transmission Provider shall execute the Optional Interconnection Study Agreement and deliver a fully executed copy to the Interconnection Customer.

10.2 Scope of Optional Interconnection Study

The Optional Interconnection Study will consist of a sensitivity analysis based on the assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement. The Optional Interconnection Study will also identify the Transmission Provider's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide Interconnection Service based upon the results of the Optional Interconnection Study. The Optional Interconnection Study shall be performed solely for informational purposes. The Transmission Provider shall use Reasonable Efforts to coordinate the study with any Affected Systems that may be affected by the types of Interconnection Services that are being studied. The Transmission Provider shall utilize existing studies to the extent practicable in conducting the Optional Interconnection Study.

10.3 Optional Interconnection Study Procedures

The executed Optional Interconnection Study Agreement, the prepayment, and technical and other data called for therein must be provided to the Transmission Provider within ten (10) Business Days of Interconnection Customer receipt of the Optional Interconnection Study Agreement. The Transmission Provider shall complete the Optional Interconnection Study on a best efforts basis after allocating available study resources to non-Optional Interconnection Studies and will use Reasonable Efforts to complete the study within the time period specified in the Optional Interconnection Study Agreement. Any difference between the study payment and the actual cost of the study shall be paid to the Transmission Provider or refunded to the Interconnection Customer, as appropriate. Upon request, the Transmission Provider shall provide the Interconnection Customer supporting documentation and work papers and databases or data developed in the preparation of the Optional Interconnection Study, subject to confidentiality arrangements consistent with Section 13.1.

SECTION 11. STANDARD GENERATOR INTERCONNECTION AGREEMENT (GIA)

11.1 Tender

Interconnection Customer shall tender comments on the draft Interconnection Facilities Study Report within thirty (30) Calendar Days of receipt of the report. Within fifteen (15) Business Days after the comments are submitted, Transmission Provider shall tender the final Interconnection Facilities Study Report and a draft GIA, together with draft appendices completed to the extent practical. The draft GIA shall be in the form of the Transmission Provider's Board-approved standard form GIA, which is in Appendix 6. Interconnection Customer shall return the completed draft appendices within thirty (30) Calendar Days.

11.2 Negotiation

Notwithstanding Section 11.1, at the request of the Interconnection Customer the Transmission Provider shall begin negotiations with the Interconnection Customer concerning the appendices to the GIA at any time after the Interconnection Customer executes the Interconnection Facilities Study Agreement. The Transmission Provider and the Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft GIA for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study Report. The Transmission Provider shall provide to the Interconnection Customer a final GIA with completed appendices for the purposes of execution within fifteen (15) Calendar Days after the completion of the negotiation process.

If the Interconnection Customer determines that negotiations are at an impasse, it may request termination of the negotiations and request submission of the unexecuted GIA with the Board for review and approval or initiate Dispute Resolution procedures pursuant to Section 13.5. If the Interconnection Customer requests termination of the negotiations, but within fifteen (15) Calendar Days thereafter either fails to request the filing of the unexecuted GIA with the Board or to initiate Dispute Resolution procedures pursuant to Section 13.5, it shall be deemed to have withdrawn its Interconnection Request.

Unless otherwise agreed by the Parties in writing, if, within ninety (90) Calendar Days of tender of the final Interconnection Facilities Study Report, the Interconnection Customer has not:

a) executed the GIA;

b) requested filing of an unexecuted GIA with the Board for review and approval; or

c) initiated Dispute Resolution procedures pursuant to Section 13.5

it shall be deemed to have withdrawn its Interconnection Request.

11.3 Execution and Filing

Within fifteen (15) Calendar Days after receipt of the final GIA, the Interconnection Customer shall provide the Transmission Provider (a) reasonable evidence of continued Site Control or (b) posting of $250,000, non-refundable additional security, which shall be applied toward future construction costs. At the same time, Interconnection Customer shall provide: i) demonstration that major equipment, i.e. generators, interconnection power transformers have been ordered for the Generating Facility, and ii) a deposit or Letter of Credit acceptable to the Transmission Provider in an amount equal to the estimated Network Upgrade Costs identified in the Interconnection Facilities Study. The Interconnection Customer shall also either: (i) execute two originals of the tendered GIA and return them to the Transmission Provider; or (ii) request in writing that the Transmission Provider file with the Board a GIA in unexecuted form.

As soon as practicable, but not later than ten (10) Business Days after receiving either the two executed originals of the tendered GIA (if it does not conform with Board-approved standard form of GIA) or the request to file an unexecuted GIA, the Transmission Provider shall file the GIA with the Board, together with its explanation of any matters as to which the Interconnection Customer and the Transmission Provider disagree and support for the costs that the Transmission Provider proposes to charge to the Interconnection Customer under the GIA. An unexecuted GIA should contain terms and conditions deemed appropriate by the

Transmission Provider for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted GIA, they may proceed pending Board action.

11.4 Commencement of Interconnection Activities

If the Interconnection Customer executes the final GIA, the Transmission Provider and the Interconnection Customer shall perform their respective obligations in accordance with the terms of the GIA, subject to modification by the Board. Upon submission of an unexecuted GIA, both Interconnection Customer and Transmission Provider shall promptly comply with the unexecuted GIA, subject to modification by the Board.

SECTION 12. CONSTRUCTION OF TRANSMISSION PROVIDER'S INTERCONNECTION FACILITIES AND NETWORK UPGRADES.

12.1 Schedule

The Transmission Provider and the Interconnection Customer shall negotiate in good faith concerning a schedule for the construction of the Transmission Provider's Interconnection Facilities and the Network Upgrades.

12.2 Construction Sequencing

12.2.1 General

In general, the In-Service Date of an Interconnection Customers seeking interconnection to the Transmission System will determine the sequence of construction of Network Upgrades.

12.2.2 Advance Construction of Network Upgrades that are an Obligation of an Entity other than the Interconnection Customer

An Interconnection Customer with a GIA, in order to maintain its In-Service Date, may request that the Transmission Provider advance to the extent necessary the completion of Network Upgrades that:

(i) were assumed in the Interconnection Studies for such Interconnection Customer,

(ii) are necessary to support such In-Service Date, and

(iii) would otherwise not be completed, pursuant to a contractual obligation of an entity other than the Interconnection Customer that is seeking interconnection to the Transmission System, in time to support such In-Service Date. Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that the Interconnection Customer commits to pay Transmission Provider:

(i) any associated expediting costs and

(ii) the cost of such Network Upgrades.

The Transmission Provider will refund to the Interconnection Customer both the expediting costs and the cost of Network Upgrades, in accordance with Article 11.4 of the GIA. Consequently, the entity with a contractual obligation to construct such Network Upgrades shall be obligated to pay only that portion of the costs of the Network Upgrades that Transmission Provider has not refunded to the Interconnection Customer. Payment by that entity shall be due on the date that it would have been due had there been no request for advance construction. The Transmission Provider shall forward to the Interconnection Customer the amount paid by the entity with a contractual obligation to construct the Network Upgrades as payment in full for the outstanding balance owed to the Interconnection Customer. The Transmission Provider then shall refund to that entity the amount that it paid for the Network Upgrades, in accordance with Article 11.4 of the GIA

12.2.3 Advancing Construction of Network Upgrades that are Part of an Expansion Plan of the Transmission Provider

An Interconnection Customer with a GIA, in order to maintain its In-Service Date, may request that the Transmission Provider advance to the extent necessary the completion of Network Upgrades that:

(i) are necessary to support such In-Service Date and

(ii) would otherwise not be completed, pursuant to an expansion plan of the Transmission Provider, in time to support such In-Service Date.

Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that the Interconnection Customer commits to pay Transmission Provider any associated expediting costs. The Interconnection Customer shall be entitled to transmission credits, if any, for any expediting costs paid.

12.2.4 Amended Interconnection System Impact Study

An Interconnection System Impact Study will be amended to determine the facilities necessary to support the requested In-Service Date. This amended study will include those transmission and Generating Facilities that are expected to be in service on or before the requested In-Service Date.

SECTION 13. MISCELLANEOUS.

13.1 Confidentiality

A Party providing Confidential Information shall notify, either orally or in writing, the Party receiving the information, that the information provided is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that Confidential Information warrants confidential treatment, Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

13.1.1 Scope

Confidential Information shall not include information that the receiving Party can demonstrate:

(1) is generally available to the public other than as a result of a disclosure by the receiving Party;

(2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party;

(3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential;

(4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party;

(5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of the GIA; or

(6) is required, in accordance with Section 13.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the GIA.

Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

13.1.2 Release of Confidential Information

Neither Party shall release or disclose Confidential Information to any other person, except to its employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this Section 13.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any subsequent release of Confidential Information in contravention of this Section 13.1.

13.1.3 Rights

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

13.1.4 No Warranties

By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

13.1.5 Standard of Care

Each Party shall use at least the same standard of care to protect the other Party's Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use the other Party's Confidential Information solely to fulfill its obligations to the other Party under these procedures or its regulatory requirements.

13.1.6 Order of Disclosure

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of the GIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

13.1.7 Remedies

The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Section 13.1. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Section 13.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Section 13.1, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 13.1.

13.1.8 Disclosure to the Board or its Staff

Notwithstanding anything in this Section 13.1 to the contrary if the Board or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the GIP, the Party shall provide the requested information to the Board or its staff, within the time provided for in the request for information. In providing the information to the Board or its staff, the Party must, request that the information be treated as confidential and non-public by the Board and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to the Board or its staff. The Party shall notify the other Party to the GIA when its is notified by the Board or its staff that a request to release Confidential Information has been received by the Board, at which time either of the Parties may respond before such information would be made public.

13.1.9 Subject to the exception in Sections 13.1.2 and 13.1.8, any information that a Party claims is Confidential Information shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is

(i) required by law;

(ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute;

(iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or

(iv) necessary to fulfill its obligations under this GIP or as a transmission service provider or an Operating Area operator including disclosing the Confidential Information to an RTO or ISO or to a subregional, regional or national reliability organization or planning group.

A Party providing Confidential Information shall notify, either orally or in writing, the Party receiving the information, that the information provided is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

13.1.10 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

13.1.11 The Transmission Provider shall, at Interconnection Customer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.

13.2 Delegation of Responsibility

The Transmission Provider may use the services of subcontractors as it deems appropriate to perform its obligations under this GIP. Transmission Provider shall remain primarily liable to the Interconnection Customer for the performance of such subcontractors and compliance with its obligations of this GIP. The subcontractor shall keep all information provided confidential and shall use such information solely for the performance of such obligation for which it was provided and no other purpose.

13.3 Obligation for Study Costs

Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Studies. Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded, except as otherwise provided herein, to Interconnection Customer or offset against the cost of any future Interconnection Studies associated with the applicable Interconnection Request prior to beginning of any such future Interconnection Studies. Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study. Interconnection Customer shall pay any such undisputed costs within 30 Calendar Days of receipt of an invoice therefore. The Transmission Provider shall not be obligated to perform or continue to perform any studies unless Interconnection Customer has paid all undisputed amounts in compliance herewith.

In the event that a re-study deposit paid by the Interconnection Customer has been utilized by the Transmission Provider to conduct re-studies it deems necessary, the Transmission Provider shall provide a detailed and itemized accounting to the Interconnection Customer regarding the use of such re-study deposit. Any refunds of the Interconnection Customer's re-study deposits will be made upon completion of all required re-studies per Sections 6.4, 7.6 and 8.5, or upon the determination, by the Transmission Provider, that there are no material impacts to lower-queued interconnection requests as a result of withdrawal per Section 3.6, Modification per Section 4.4, re-designation of the Point of Interconnection per Section 6.1 or 7.2 for the applicable Interconnection Request. Refunds will be made to the Interconnection Customer, in the amount that the Interconnection Customer's study or re-study deposit payments exceeds the costs the Transmission Provider has incurred to conduct all required re-studies per Sections 6.4, 7.6 and 8.5. Where the Transmission Provider has determined that there are no material impacts to lower-queued interconnection requests as a result of withdrawal per Section 3.6, Modification per Section 4.4, re-designation of the Point of Interconnection per Section 6.1 or 7.2 for the applicable Interconnection Request, all unused deposits that have been paid by the Interconnection Customer shall be accounted for and/or refunded no later than 30 Calendar Days following the execution of a GIA by the Interconnection Customer.

In any event, all deposits that have been paid by the Interconnection Customer shall be accounted for and/or refunded within a reasonable period from the final withdrawal of the Interconnection Customer's Interconnection Request from the interconnection queue.

13.4 Third Parties Conducting Studies

If

(i) at the time of the signing of an Interconnection Study Agreement there is disagreement as to the estimated time to complete an Interconnection Study,

(ii) the Interconnection Customer receives notice pursuant to Sections 6.3, 7.4 or 8.3 that the Transmission Provider will not complete an Interconnection Study within the applicable timeframe for such Interconnection Study, or

(iii) the Interconnection Customer receives neither the Interconnection Study nor a notice under Sections 6.3, 7.4 or 8.3 within the applicable timeframe for such Interconnection Study, then the Interconnection Customer may require the Transmission Provider to utilize a third party consultant reasonably acceptable to Interconnection Customer and Transmission Provider to perform such Interconnection Study under the direction of the Transmission Provider. At other times, Transmission Provider may also utilize a third party consultant to perform such Interconnection Study, either in response to a general request of the Interconnection Customer, or on its own volition.

In all cases, use of a third party consultant shall be in accord with Article 26 of the GIA (Subcontractors) and limited to situations where the Transmission Provider determines that doing so will help maintain or accelerate the study process for the Interconnection Customer's pending Interconnection Request and not interfere with the Transmission Provider's progress on Interconnection Studies for other pending Interconnection Requests. In cases where the Interconnection Customer requests use of a third party consultant to perform such Interconnection Study, Interconnection Customer and Transmission Provider shall negotiate all of the pertinent terms and conditions, including reimbursement arrangements and the estimated study completion date and study review deadline. Transmission Provider shall convey all workpapers, data bases, study results and all other supporting documentation prepared to date with respect to the Interconnection Request as soon as soon as practicable upon Interconnection Customer's request subject to the confidentiality provision in Section 13.1. In any case, such third party contract may be entered into with either the Interconnection Customer or the Transmission Provider at the Transmission Provider’s discretion. In the case of (iii) the Interconnection Customer maintains its right to submit a claim to Dispute Resolution to recover the costs of such third party study. Such third party consultant shall be required to comply with this GIP, Article 26 of the GIA (Subcontractors), and the relevant Tariff procedures and protocols as would apply if the Transmission Provider were to conduct the Interconnection Study and shall use the information provided to it solely for purposes of performing such services and for no other purposes. The Transmission Provider shall cooperate with such third party consultant and Interconnection Customer to complete and issue the Interconnection Study in the shortest reasonable time.

13.5 Disputes

13.5.1 External Arbitration Procedures

In the event of a dispute arising between the Parties as to the subject matter of this GIP that cannot be resolved between them, the Parties agree to submit the dispute to binding arbitration, pursuant to the terms of the *Commercial Arbitration Act*, S.N.S. 1999, c.5. In particular, the Parties agree to utilize the arbitration procedure attached as Schedule "A" to the *Commercial Arbitration Act* in the conduct of the arbitration. Any matter in dispute that is submitted for arbitration shall be heard by a single arbitrator chosen unanimously by the parties. In the event the parties cannot agree on a person to act as a single arbitrator, each party shall choose one panelist and the two panelists shall choose an independent third panelist who shall also chair the arbitration. No such arbitrator shall have previously been employed by either party and shall not have a direct or indirect interest in either party or the subject matter of the arbitration. The cost of the arbitration, excluding a parties legal fees and disbursements shall, unless otherwise ordered by the arbitrator or the panel, be borne equally by the parties.

13.5.2 Arbitration Decisions

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within 90 Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the GIA and GIP and shall have no power to modify or change any provision of the GIA and GIP in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction.

Amendments to the

Standard Generator Interconnection Agreement

for the Renewable to Retail Application.

Article 1: Definitions have been added and amended.

Article 11: Section 11.4.2 has been added.

STANDARD GENERATOR INTERCONNECTION AND OPERATING AGREEMENT (GIA)

[INSERT INTERCONNECTION CUSTOMER NAME]
[XX] MW WIND GENERATING FACILITY,
[INSERT COUNTY NAME] COUNTY, NOVA SCOTIA

Deleted:

Deleted: July 2015

TABLE OF CONTENTS

Deleted: 21
Deleted: 21
Deleted: 21
Deleted: 22
Deleted: 23
Deleted: 24
Deleted: 24
Deleted: 24
Deleted: 24
Deleted: 24
Deleted: 25
Deleted: 26
Deleted: 28
Deleted: 29
Deleted: 29
Deleted: 29
Deleted: 29
Deleted: 30
Deleted: 31
Deleted: 31
Deleted: 34
Deleted: 35
Deleted: 36
Deleted: 37
Deleted: 37
Deleted: 38
Deleted: 38
Deleted: 39
Deleted: 39
Deleted: 40
Deleted: 41
Deleted: 42
Deleted: 43
Deleted: 43
Deleted: 43
Deleted: 44
Deleted: 44
Deleted: 44
Deleted: 45
Deleted: 45
Deleted:
Deleted: July 2015

GIP Appendix 6 – Standard Generator Interconnection and Operating Agreement

Deleted: 45
Deleted: 45
Deleted: 46
Deleted: 46
Deleted: 47
Deleted: 47
Deleted: 47
Deleted: 48
Deleted: 48
Deleted: 48
Deleted: 49
Deleted: 49
Deleted: 49
Deleted: 50
Deleted: 50
Deleted: 50
Deleted: 50
Deleted: 51
Deleted: 51
Deleted: 52
Deleted: 52
Deleted: 52
Deleted: 52
Deleted: 53
Deleted: 54
Deleted: 54
Deleted: 55
Deleted: 58
Deleted: 58
Deleted: 59
Deleted: 60
Deleted: 60
Deleted: 61
Deleted: 61
Deleted: 61
Deleted: 61
Deleted: 62
Deleted: 62
Deleted: 62
Deleted: 62
Deleted: 63
Deleted: 63
Deleted: 63
Deleted: 63
Deleted: 64
Deleted: 64
Deleted: 64
Deleted: 64
Deleted: 65
Deleted: 65
Deleted: ¶
Deleted: 66
Deleted: 67
Deleted: 68
Deleted: 68
Deleted: 68
Deleted: …●July 2015 ... [1]

GIP Appendix 6 – Standard Generator Interconnection and Operating Agreement

Deleted: 68
Deleted: 69
Deleted: 69
Deleted: 69
Deleted: 69
Deleted: 70
Deleted: 71
Deleted: 71
Deleted: 72
Deleted: 72
Deleted: 73
Deleted: 73
Deleted: 74
Deleted: 74
Deleted: 74
Deleted: 75
Deleted: 75
Deleted: 75
Deleted: 75
Deleted: 75
Deleted: 76
Deleted: 76
Deleted: 76
Deleted: 77
Deleted: 77
Deleted: 77
Deleted: 77
Deleted: 78
Deleted: 78
Deleted: 78
Deleted: 78
Deleted: 79
Deleted: 80
Deleted: 80
Deleted: 83
Deleted: 83
Deleted: 83
Deleted: 84
Deleted: 84
Deleted: 84
Deleted: 84
Deleted: 84
Deleted: 84
Deleted: 85
Deleted: 85
Deleted: 86
Deleted: 86
Deleted: 86
Deleted: 87
Deleted: 87
Deleted: 87
Deleted: 88
Deleted: 88
Deleted: 90
Deleted: 90
Deleted: 90
Deleted: ...●July 2015 ... [2]

Deleted: 90
Deleted: 91
Deleted: 92
Deleted: 93
Deleted: 93
Deleted: 93
Deleted: 94
Deleted: 94
Deleted: 94
Deleted: 94
Deleted: 95
Deleted: 95
Deleted: 95
Deleted: 95
Deleted: 96
Deleted: 96
Deleted: 96
Deleted: 96
Deleted: 97
Deleted: 97
Deleted: 97
Deleted: 97
Deleted: 98
Deleted: 98
Deleted: 98
Deleted: 98
Deleted: 99
Deleted: 99
Deleted: 99
Deleted: 100
Deleted: 101
Deleted: 101
Deleted: 101
Deleted: 102
Deleted: 102
Deleted: 102
Deleted: 102
Deleted: 103

Deleted:
Deleted: July 2015

APPENDICES

APPENDIX A TO GIA:	**INTERCONNECTION FACILITIES, NETWORK UPGRADES AND DISTRIBUTION UPGRADES**
APPENDIX B TO GIA:	**MILESTONES**
APPENDIX C TO GIA:	**INTERCONNECTION DETAILS**
APPENDIX D TO GIA:	**SECURITY ARRANGEMENTS DETAILS**
APPENDIX E TO GIA:	**INITIAL SYNCHRONIZATION DATE AND COMMERCIAL OPERATION DATE**
APPENDIX F TO GIA:	**ADDRESSES FOR DELIVERY OF NOTICES AND BILLINGS**
APPENDIX G TO GIA:	**INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT**
APPENDIX H TO GIA:	**REGULATORY AND GOVERNMENT AGENCY APPROVALS**

Deleted:

Deleted: July 2015

STANDARD GENERATOR INTERCONNECTION AND OPERATING AGREEMENT

THIS STANDARD GENERATOR INTERCONNECTION AND OPERATING AGREEMENT ("Agreement" or "GIA") is made and entered into this ____ day of ________ 20__, by and between _______________, a ___________ organized and existing under the laws of the Province of ________ ("Interconnection Customer" with a Generating Facility), and _____________, a [corporation] organized and existing under the laws of the Province of ____________ ("Transmission Provider and/or Transmission Owner"). Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, Transmission Provider operates the Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Interconnection Customer and Transmission Provider have agreed to enter into this Agreement for the purpose of interconnecting the Generating Facility with the Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Generator Interconnection and Operating Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used.

Deleted: February 10, 2010.

GIP Appendix 6 – Standard Generator Interconnection and Operating Agreement

ARTICLE 1. DEFINITIONS

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate - the term "affiliate" shall be interpreted in accordance with Sections 2(2), 2(3), and 2(4) of the Nova Scotia Companies Act[1].

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

---

1 1 **Deemed affiliate**

2(2) A company shall be deemed to be an affiliate of another company if one of them is the subsidiary of the other or if both are subsidiaries of the same company or if each of them is controlled by the same person.

Deemed control

2(3) A company shall be deemed to be controlled by another person or by two or more companies if

(a) voting securities of the first-mentioned company carrying more than fifty per cent of the votes for the election of directors are held, otherwise than by way of security only, by or for the benefit of the other person or by or for the benefit of the other companies; and

(b) the votes carried by such securities are entitled, if exercised, to elect a majority of the directors of the first-mentioned company.

Deemed subsidiary

2(4) A company shall be deemed to be a subsidiary of another company if

(a) it is controlled by

(i) that other, or

(ii) that other and one or more companies each of which is controlled by that other, or

(iii) two or more companies each of which is controlled by that other; or

(b) it is a subsidiary of a company that is that other's subsidiary. R.S., c. 81, s. 2; 1990, c.15, s. 2.

Deleted: February 10, 2010.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, provincial and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the Northeast Power Coordinating Council or any successor thereto.

Applicable Reliability Standards shall mean the requirements and guidelines of the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected, and the NSPI Interconnection Guidelines and Standards as set out in Appendix D to this document.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Board shall mean the Nova Scotia Utility and Review Board.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Generator Interconnection and Operating Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Generator Interconnection and Operating Agreement.

Business Day shall mean Monday to Friday, inclusive, excluding holidays. The regular business hours on a Business Day are from 08:30 to 16:30 Atlantic Time.

Calendar Day shall mean any day including Saturday, Sunday or a holiday.

Commercial Operation Date shall mean the date on which Interconnection Customer commences commercial operation of the unit at the Generating Facility after Trial Operation of such unit has been completed as confirmed in writing substantially in the form shown in Appendix E of the Standard Generator Interconnection and Operating Agreement.

Deleted: February 10, 2010.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, as well as any information relating to a Party's technology, research and development, business affairs and pricing whether such information is supplied prior to or after the execution of the GIA, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electric system or group of systems that meet(s) the requirements of the NPCC Control Area Certification Process.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Generator Interconnection and Operating Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to distribute electricity to ultimate usage points such as homes and industries either directly from nearby generators or from interchanges from the Transmission System.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Generator Interconnection and Operating Agreement becomes effective in accordance with Article 2.1 of the Standard Generator Interconnection and Operating Agreement.

Deleted: February 10, 2010.

Emergency Condition shall mean a condition or situation:

(1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or

(2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or

(3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Standard Generator Interconnection and Operating Agreement to possess black start capability.

Energy Resource Interconnection Service (ER Interconnection Service) shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Deleted: February 10, 2010.

Force Majeure shall mean an event, condition, occurrence or circumstance beyond the reasonable control and not attributable to the fault or negligence of the Party claiming Force Majeure, which, despite all reasonable efforts at a reasonable cost of the Party claiming the Force Majeure to prevent its occurrence or mitigate its effects, causes a delay or disruption in the performance of any obligation (other than the obligation to pay monies due) imposed on such Party hereunder, including, without limitation, any act of God, labour disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment if caused by an event which would constitute Force Majeure, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control.

Generating Facility shall mean Interconnection Customer's device for the production of electricity for interconnection to the Transmission System at voltages 69 kV and above as identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean those practices, methods or acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America) that at a particular time, in the exercise of reasonable judgment, would have been expected to accomplish the desired result in a manner consistent with regulations, reliability, safety, environmental protection, economy and expedition as applied and practiced in the utility industry with respect to power generation, delivery, purchase and sale.

Governmental Authority shall mean any national, international, federal, provincial, municipal, county, regional or local government, organization or duly constituted authority having jurisdiction, and includes:

(a) any department, commission, bureau, board, administrative agency or regulatory body of any government having jurisdiction; and

Deleted: February 10, 2010.

(b) any person or corporation acting as an authorized agent thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially electrically connected to, and energized by, the Transmission System and upon which Trial Operation begins..

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Generator Interconnection and Operating Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically

Deleted: February 10, 2010.

interconnect the Generating Facility to the Transmission Provider’s Transmission System, and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission Provider's Transmission System. The scope of the study is defined in Section 8 of the Standard Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider’s Transmission System, the scope of which is described in Section 6 of the Standard Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of (except for increases in capacity permitted by Section 2.6 of the Standard Generator Interconnection Procedures), or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider’s Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer’s Generating Facility to the Transmission Provider’s Transmission System and enabling it to receive electric energy and capacity from the

Deleted: February 10, 2010.

Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Generator Interconnection and Operating Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Generator Interconnection Procedures.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Licenced Retail Supplier (LRS): A Retail Supplier who:

(a) holds a valid Retail Supplier Licence; and

(b) has a valid LRS Participation Agreement executed with Nova Scotia Power Inc.

For certainty, a Wholesale Customer is not a Licenced Retail Supplier.

LRS Participation Agreement: The agreement (and any amendments or supplements thereto) between an LRS and Nova Scotia Power Inc. with respect to the sale of renewable low-impact electricity by the LRS in the form approved by the Board.

Deleted: February 10, 2010.

Load Serving Entity shall mean one of the following:

(i) Nova Scotia Power Inc. (NSPI), or

(ii) a Nova Scotia municipal electric utility.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Generator Interconnection and Operating Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Generator Interconnection and Operating Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

Network Resource shall mean that portion of a Generating Facility that is integrated with the Transmission Provider's Transmission System, designated as a Network Resource pursuant to the terms of the Tariff, and subjected to redispatch directives as ordered by the Transmission Provider in accordance with the Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service (NR Interconnection Service) shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission Provider's Transmission System

Deleted: February 10, 2010.

(1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or

(2) in an RTO (Regional Transmission Organization) or ISO (Independent System Operator) with market based congestion management, in the same manner as Network Resources.

Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Customer interconnects to the Transmission Provider's Transmission System to accommodate the interconnection of the Generating Facility to the Transmission Provider's Transmission System.

NPCC shall mean the Northeast Power Coordinating Council and its successor organizations.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Generator Interconnection and Operating Agreement or its performance.

Operating Area shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Operating Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Deleted: February 10, 2010.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Generator Interconnection and Operating Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Generator Interconnection and Operating Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Retail Customer: This term has the same meaning as under the *Electricity Act*, S.N.S. 2004, c. 25. For certainty, a customer of a municipal utility (as defined under the *Electricity Act*) is not a Retail Customer.

Retail Supplier: This term has the same meaning as under the *Electricity Act*, S.N.S. 2004, c. 25.

Retail Supplier Licence: A Retail Supplier licence issued by the Board in accordance with the *Electricity Act*, S.N.S. 2004, c. 25 and regulations made thereunder which authorizes a person to sell renewable low-impact electricity generated within the Province of Nova Scotia.

Deleted: February 10, 2010.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, exchanging information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, analyzing such information, and determining the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating:

(1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; or

(2) an option to purchase or acquire a leasehold site for the purpose of constructing the Generating Facility

Stand Alone Network Upgrades shall mean Network Upgrades that the Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Generator Interconnection and Operating Agreement.

Standard Generator Interconnection and Operating Agreement (GIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility, that is included in the Transmission Provider's Tariff.

Standard Generator Interconnection Procedures (GIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility that are included in the Transmission Provider's Tariff.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect:

(1) the Transmission System from faults or other electrical disturbances occurring at the Generating Facility and

Deleted: February 10, 2010.

(2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission System or on other delivery systems or other generating systems to which the Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with the Board, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Generator Interconnection and Operating Agreement to the extent necessary.

Transmission Provider shall mean Nova Scotia Power Inc.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Generator Interconnection and Operating Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to commercial operation.

Wholesale Customer: This term has the same meaning as under the *Electricity Act*, S.N.S. 2004, c. 25.

ARTICLE 2. EFFECTIVE DATE, TERM AND TERMINATION

Deleted: February 10, 2010.

2.1 Effective Date

This GIA shall become effective upon execution by the Parties subject to acceptance by the Board (if applicable), or if filed unexecuted, upon the date specified by the Board. Transmission Provider shall promptly file this GIA with the Board upon execution in accordance with Article 3.1, if required.

2.2 Term of Agreement

Subject to the provisions of Article 2.3, this GIA shall remain in effect for a period of five years from the Effective Date or such other longer period as the Interconnection Customer may request (*Term to be Specified in Individual Agreements*) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures

This GIA may be terminated as follows:

2.3.1 Written Notice

The Interconnection Customer may terminate this GIA after giving the Transmission Provider 90 Calendar Days advance written notice; or by Transmission Provider notifying the Board after the Generating facility permanently ceases commercial operation.

2.3.2 Default

Either Party may terminate this GIA in accordance with Article 17.

Deleted: February 10, 2010.

Notwithstanding the foregoing, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with the Board of a notice of termination of this GIA, which notice has been accepted for filing by the Board.

2.4 Termination Costs

If a Party elects to terminate this Agreement pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the other Party's receipt of such notice of termination, that are the responsibility of the terminating Party under this GIA. In the event of termination by either Party, both Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this GIA, unless otherwise ordered or approved by the Board:

2.4.1 With respect to any portion of the Transmission Provider's Interconnection Facilities that have not yet been constructed or installed, the Transmission Provider shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and the Transmission Provider shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Provider for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Provider shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by the Transmission Provider to cancel any pending orders of or return such materials, equipment, or contracts.

Deleted: February 10, 2010.

If an Interconnection Customer terminates this GIA, it shall be responsible for all costs incurred or that will be incurred by the Transmission Provider in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which the Transmission Provider has incurred or will incur expenses and has not been reimbursed by the Interconnection Customer.

2.4.2 Transmission Provider may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Provider shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this GIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 Disconnection

Upon termination of this GIA, the Parties will take all appropriate steps to disconnect the Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this GIA or such non-terminating Party otherwise is responsible for these costs under this GIA.

Deleted: February 10, 2010.

2.6 Survival

This GIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this GIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this GIA was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this GIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

ARTICLE 3. REGULATORY FILINGS

3.1 Filing

Transmission Provider shall file this GIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this GIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

ARTICLE 4. SCOPE OF SERVICE

4.1 Interconnection Product Options

Interconnection Customer has selected the following (checked) type of Interconnection Service:

☐ **Energy Resource Interconnection Service**

Deleted: February 10, 2010.

Or

❑ **Network Resource Interconnection Service**

4.1.1 Energy Resource Interconnection Service (ER Interconnection Service).

4.1.1.1 The Product

ER Interconnection Service allows Interconnection Customer to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive ER Interconnection Service, the Transmission Provider shall construct facilities identified in Appendix A. ER Interconnection Service does not in and of itself convey any transmission delivery service.

4.1.1.2 Transmission Delivery Service Implications

Under ER Interconnection Service, the Interconnection Customer will be able to inject power from the Generating Facility into and deliver power across the interconnecting Transmission Provider's Transmission System on an "as available" basis up to the amount of MW's identified in the applicable stability and steady state studies to the extent the upgrades initially required to qualify for ER Interconnection Service have been constructed. Where eligible to do so the Interconnection Customer may place a bid to sell into the market up to the maximum identified Generating Facility output, subject to any conditions specified in the interconnection service approval, and the Generating Facility will be dispatched to the extent the Interconnection Customer's bid clears. In all other instances, no transmission delivery service from the Generating Facility is assured, but the Interconnection Customer may obtain point-to-point transmission delivery service or be used for secondary network transmission service, pursuant to the Transmission

Deleted: February 10, 2010.

Provider's Tariff, up to the maximum output identified in the stability and steady state studies. In those instances, in order for the Interconnection Customer to obtain the right to deliver or inject energy beyond the Generating Facility Point of Interconnection or to improve its ability to do so, transmission delivery service must be obtained pursuant to the provisions of the Transmission Provider's Tariff. The Interconnection Customer's ability to inject its Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of the Transmission Provider's Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of firm point-to-point transmission service may require the construction of additional Network Upgrades.

4.1.2 Network Resource Interconnection Service (NR Interconnection Service)

4.1.2.1 The Product

The Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Generating Facility

(1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or

(2) in an ISO or RTO with market based congestion management, in the same manner as all other Network Resources.

NR Interconnection Service in and of itself does not convey any transmission delivery service.

4.1.2.2 Transmission Delivery Service Implications

Deleted: February 10, 2010.

NR Interconnection Service allows the Interconnection Customer's Generating Facility to be designated by any Network Customer under the Tariff on the Transmission Provider's Transmission System as a Network Resource, up to the Generating Facility's full output, on the same basis as all other existing Network Resources interconnected to the Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although NR Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Generating Facility in the same manner as it accesses Network Resources. A Generating Facility receiving NR Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all Generating Facilities that are similarly situated.

NR Interconnection Service does not necessarily provide the Interconnection Customer with the capability to physically deliver the output of its Generating Facility to any particular load on the Transmission Provider's Transmission System without incurring congestion costs. In the event of transmission constraints on the Transmission Provider's Transmission System, the Interconnection Customer's Generating Facility shall be subject to the applicable congestion management procedures in the Transmission Provider's Transmission System in the same manner as Network Resources.

Deleted: February 10, 2010.

There is no requirement either at the time of study or interconnection, or at any point in the future, that the Interconnection Customer's Generating Facility be designated as a Network Resource by a Network Service Customer under the Tariff or that the Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Generating Facility as a Network Resource, it must do so pursuant to the Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining NR Interconnection Service, any future transmission service request for delivery from the Generating Facility within the Transmission Provider's Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Generating Facility be undertaken, regardless of whether or not such Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Generating Facility. To the extent the Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Generating Facility outside the Transmission Provider's Transmission System, such request may require additional studies and upgrades in order for the Transmission Provider to grant such request.

4.2 Provision of Service

Transmission Provider shall provide Interconnection Service for the Generating Facility at the Point of Interconnection.

4.3 Performance Standards

Each Party shall perform all of its obligations under this GIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to

Deleted: February 10, 2010.

the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this GIA for its compliance therewith. If such Party is the Transmission Provider or Transmission Owner, then that Party shall amend the GIA and submit the amendment to the Board for approval.

4.4 No Transmission Delivery Service

The execution of this GIA does not constitute a request for, nor the provision of, any transmission delivery service under the Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or point of delivery.

4.5 Interconnection Customer Provided Services

The services provided by Interconnection Customer under this GIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.6.

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

5.1 Options

Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either Standard Option or Alternate Option set forth below for completion of the Transmission Provider's Interconnection Facilities and Network Upgrades as set forth in Appendix A, Interconnection Facilities and Network Upgrades, and such dates and selected option shall be set forth in Appendix B, Milestones.

5.1.1 Standard Option

Deleted: February 10, 2010.

The Transmission Provider shall design, procure, and construct the Transmission Provider's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete the Transmission Provider's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. The Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event the Transmission Provider reasonably expects that it will not be able to complete the Transmission Provider's Interconnection Facilities and Network Upgrades by the specified dates, the Transmission Provider shall promptly provide written notice to the Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 Alternate Option

If the dates designated by Interconnection Customer are acceptable to Transmission Provider, the Transmission Provider shall so notify Interconnection Customer within 30 Calendar Days, and shall assume responsibility for the design, procurement and construction of the Transmission Provider's Interconnection Facilities by the designated dates.

If Transmission Provider subsequently fails to complete Transmission Provider's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B, Milestones; Transmission Provider shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable Operating Area operator refuses to grant outages, requested by the Transmission Provider using Reasonable Efforts, to install or modify equipment.

Deleted: February 10, 2010.

5.1.3 Option to Build

If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, the Transmission Provider shall so notify the Interconnection Customer within 30 Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A to the GIA. Except for Stand Alone Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 Negotiated Option

If the Interconnection Customer elects not to exercise its option under Article 5.1.3, Option to Build, Interconnection Customer shall so notify Transmission Provider within 30 Calendar Days, and the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection Customer) pursuant to which Transmission Provider is responsible for the design, procurement and construction of the Transmission Provider's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Transmission Provider shall assume responsibility for the design, procurement and construction of the Transmission Provider's Interconnection Facilities and Network Upgrades pursuant to 5.1.1, Standard Option.

5.2 General Conditions Applicable to Option to Build

Deleted: February 10, 2010.

If Interconnection Customer assumes responsibility for the design, procurement and construction of the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades,

(1) the Interconnection Customer shall engineer, procure equipment, and construct the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by the Transmission Provider;

(2) Interconnection Customer's engineering, procurement and construction of the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Provider shall review and approve the engineering design, equipment acceptance tests, and the construction of the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider a schedule for construction of the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider;

(5) at any time during construction, Transmission Provider shall have the right to gain unrestricted access to the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

Deleted: February 10, 2010.

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Provider, the Interconnection Customer shall be obligated to remedy deficiencies in that portion of the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(7) the Interconnection Customer shall indemnify the Transmission Provider for claims arising from the Interconnection Customer's construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) the Interconnection Customer shall transfer control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to the Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection customer shall transfer ownership of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(10) Transmission Provider shall approve and accept for operation and maintenance the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2.; and

(11) Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information, and any other documents that are reasonably required by Transmission Provider to assure that the Interconnection facilities and Stand Alone Network Upgrades are built to the standards and specifications required by the Transmission Provider.

Deleted: February 10, 2010.

5.3 Liquidated Damages

The actual damages to the Interconnection Customer, in the event the Transmission Provider's Interconnection Facilities or Network Upgrades are not completed by the dates designated by the Interconnection Customer and accepted by the Transmission Provider pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by the Transmission Provider to the Interconnection Customer in the event that Transmission Provider does not complete any portion of the Transmission Provider's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of the Transmission Provider's Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Provider has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of the Transmission Provider Interconnection Facilities and Network Upgrades for which the Transmission Provider has assumed responsibility to design, procure, and construct. The foregoing payments will be made by the Transmission Provider to the Interconnection Customer as just compensation for the damages caused to the Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this GIA.

No liquidated damages shall be paid to Interconnection Customer if:

(1) Interconnection Customer is not ready to commence use of the Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for the Generating Facility's Trial Operation or to export power from the Generating Facility on the specified dates, unless the Interconnection Customer would have been able to commence use of the

Deleted: February 10, 2010.

Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for Generating Facility's Trial Operation or to export power from the Generating Facility, but for Transmission Provider's delay;

(2) the Transmission Provider's failure to meet the specified dates is the result of the action or inaction of the Interconnection Customer or any other Interconnection Customer who has entered into an GIA with the Transmission Provider or any cause beyond Transmission Provider's reasonable control or reasonable ability to cure;

(3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 Power System Stabilizers

The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Generating Facility. If the Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, the Interconnection Customer shall immediately notify the Transmission Provider's system operator, or its designated representative. The requirements of this paragraph shall not apply to wind generators. Instead, Appendix G sets forth the specific requirements and provisions that apply to a wind Generating Facility.

5.5 Equipment Procurement

Deleted: February 10, 2010.

If responsibility for construction of the Transmission Provider's Interconnection Facilities or Network Upgrades is to be borne by the Transmission Provider, then the Transmission Provider shall commence design of the Transmission Provider's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 The Transmission Provider has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 The Transmission Provider has received written authorization to proceed with design and procurement from the Interconnection Customer by the date specified in Appendix B, Milestones; and

5.5.3 The Interconnection Customer has provided security to the Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.6 Construction Commencement

The Transmission Provider shall commence construction of the Transmission Provider's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of the Transmission Provider's Interconnection Facilities and Network Upgrades;

5.6.3 The Transmission Provider has received written authorization to proceed with construction from the Interconnection Customer by the date specified in Appendix B, Milestones; and

Deleted: February 10, 2010.

5.6.4 The Interconnection Customer has provided security to the Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.7 Work Progress

The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Either Party may, at any time, request a progress report from the other Party. If, at any time, the Interconnection Customer determines that the completion of the Transmission Provider's Interconnection Facilities will not be required until after the specified In-Service Date, the Interconnection Customer will provide written notice to the Transmission Provider of such later date upon which the completion of the Transmission Provider's Interconnection Facilities will be required.

5.8 Information Exchange

As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with the Transmission Provider's Transmission System, and shall work diligently and in good faith to make any necessary design changes. Design information shall be provided in a format compatible with the Transmission Provider's Computer Aided Drafting and Design (CADD) systems.

5.9 Limited Operation

If any of the Transmission Provider's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Generating Facility and the Interconnection Customer Interconnection

Deleted: February 10, 2010.

Facilities may operate prior to the completion of the Transmission Provider's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this GIA. Transmission Provider shall permit Interconnection Customer to operate the Generating Facility and the Interconnection Customer Interconnection Facilities in accordance with the results of such studies.

5.10 Interconnection Customer's Interconnection Facilities ("ICIF")

Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. The ICIF shall be sole use facilities.

5.10.1 Generating Facility Specifications

Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Provider at least 180 Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least 90 Calendar Days prior to the Initial Synchronization Date. Transmission Provider shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of the Transmission Provider and comment on such specifications within 30 Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Transmission Provider's Review

Transmission Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Provider, in accordance with Good Utility Practice, to

Deleted: February 10, 2010.

ensure that the ICIF are compatible with the telemetry, communications, and safety requirements of the Transmission Provider.

5.10.3 ICIF Construction

The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred 120 Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, the Interconnection Customer shall deliver to the Transmission Provider "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with the Interconnection Customer's step-up transformers, the facilities connecting the Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Generating Facilities. The Interconnection Customer shall provide Transmission Provider specifications for the excitation system, automatic voltage regulator, Generating Facility control and protection settings, transformer tap settings, and communications.

5.11 Transmission Provider's Interconnection Facilities Construction

The Transmission Provider's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within 120 Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, the Transmission Provider shall deliver to the Interconnection Customer the following "as-built" drawings, information and documents for the Transmission Provider's Interconnection Facilities: 1) Protection and Instrumentation 1-line Drawing; and 2) Interconnection Points Diagram.

The Transmission Provider will obtain control of the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

Deleted: February 10, 2010.

5.12 Access Rights

The Interconnection Customer shall furnish at no cost to the Transmission Provider any licenses, rights of way and easements with respect to lands owned or controlled by the Interconnection Customer and its agents that are necessary to enable the Transmission Provider to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to:

(i) interconnect the Generating Facility with the Transmission System;

(ii) operate and maintain the Generating Facility, the Interconnection Facilities and the Transmission System; and

(iii) disconnect or remove the Transmission Provider's facilities and equipment upon termination of this GIA.

In exercising such licenses, rights of way and easements, the Transmission Provider shall not unreasonably disrupt or interfere with normal operation of the Interconnection Customer's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Interconnection Customer and provided to the Transmission Provider.

5.13 Lands of Other Property Owners

If any part of the Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Provider or Transmission Owner, the Interconnection Customer shall at Interconnection Customer's expense procure from such persons any rights of use, licenses, rights of way and easements that are necessary to

Deleted: February 10, 2010.

construct, operate, maintain, test, inspect, replace or remove the Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property. All such rights of use, licenses, rights of way and easements shall be registered or recorded by the Interconnection Customer at the Interconnection Customer's expense in the land registration office for the registration district in which the property is situated. Easements shall be in a form acceptable to the Transmission Provider. Upon receipt of a reasonable siting request, Transmission Provider shall provide siting assistance to the Interconnection Customer comparable to that provided to the Transmission Provider's own, or an Affiliate's generation.

5.14 Permits

The allocation of the responsibilities of the Transmission Provider or Transmission Owner and the Interconnection Customer to obtain all permits, licenses and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations shall be as specified in Appendix H. The Transmission Provider or Transmission Owner and the Interconnection Customer shall cooperate with each other in good faith in obtaining any such permits, licenses and authorizations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to the Interconnection Customer comparable to that provided to the Transmission Provider's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities

Interconnection Customer may request Transmission Provider to construct, and Transmission Provider shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for the Interconnection Customer, and

Deleted: February 10, 2010.

which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension

Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this GIA with the condition that the Transmission Provider shall be left in a safe and reliable condition in accordance with Good Utility Practice and the Transmission Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider

(i) has incurred pursuant to this GIA prior to the suspension and

(ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider shall obtain Interconnection Customer's authorization to do so.

Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Transmission Provider required under this GIA pursuant to this Article 5.16, and has not requested Transmission Provider to recommence the work required under this GIA on or before the expiration of three years following commencement of such suspension, this GIA shall be deemed terminated.

Deleted: February 10, 2010.

In the event Interconnection Customer suspends work by Transmission Provider required under this Agreement pursuant to this Article 5.16, and requests Transmission Provider to recommence the work required under this Agreement, the Interconnection Customer shall be responsible for all additional costs Transmission Provider determines are necessary to restart all work by Transmission Provider associated with the construction and installation of the Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this Agreement.

5.17 Taxes

5.17.1 Interconnection Customer Payments Not Taxable

The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Provider for the installation of the Transmission Provider's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with any applicable Federal and Provincial tax laws and shall not be taxable as contributions in aid of construction or otherwise under any applicable Federal and Provincial tax laws.

5.18 Tax Status

Each Party shall cooperate with the other to maintain the other Party's tax status.

Deleted: February 10, 2010.

5.19 Modification

5.19.1 General

Either Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, that Party shall provide to the other Party sufficient information regarding such modification so that the other Party may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party at least 90 Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Provider shall provide, within 30 Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Provider's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 Standards

Any additions, modifications, or replacements made to a Party’s facilities shall be designed, constructed and operated in accordance with this GIA and Good Utility Practice.

Deleted: February 10, 2010.

5.19.3 Modification Costs

Interconnection Customer shall not be responsible for the costs of any additions, modifications, or replacements that Transmission Provider makes to the Transmission Provider's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to the Transmission Provider's Interconnection Facilities or the Transmission System, or to provide transmission service under the Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to the Interconnection Customer Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

ARTICLE 6. TESTING AND INSPECTION

6.1 Pre-Commercial Operation Date Testing and Modifications

Prior to the Commercial Operation Date, the Transmission Provider shall test the Transmission Provider's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Generating Facility and the Interconnection Customer Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Generating Facility only if it has arranged with Transmission Provider for the delivery of such test energy to the Transmission System.

6.2 Post-Commercial Operation Date Testing and Modifications

Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the

Deleted: February 10, 2010.

continued interconnection of the Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 Right to Observe Testing

Each Party shall notify the other Party in advance of its performance of tests of its Interconnection Facilities. The other Party has the right, at its own expense, to observe such testing.

6.4 Right to Inspect

Each Party shall have the right, but shall have no obligation to:

(i) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers;

(ii) review the settings of the other Party's System Protection Facilities and other protective equipment; and

(iii) review the other Party's maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment.

A Party may exercise these rights from time to time, as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that Transmission Provider obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be confidential hereunder.

Deleted: February 10, 2010.

ARTICLE 7. METERING

7.1 General

Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Provider shall install Metering Equipment at the Point of Interconnection prior to any operation of the Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Generating Facility shall be measured at or, at Transmission Provider's option, compensated to, the Point of Interconnection. Transmission Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment. All revenue metering equipment installations shall meet the Electricity and Gas Inspection Act regulations requirements in effect at the time.

7.2 Check Meters

Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Provider's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this GIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Provider or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice. Such check meters shall only be permitted if the accuracy of the revenue metering installation is not degraded unacceptably through the addition of the check meters.

Deleted: February 10, 2010.

7.3 Standards

Transmission Provider shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable Industry Canada standards.

7.4 Testing of Metering Equipment

Transmission Provider shall inspect and test all Transmission Provider-owned Metering Equipment upon installation and at least once every two years thereafter. If requested to do so by Interconnection Customer, Transmission Provider shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two years. Transmission Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Provider's failure to maintain, then Transmission Provider shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Provider shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 Metering Data

At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Provider and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating

Deleted: February 10, 2010.

conditions, as the official measurement of the amount of energy delivered from the Generating Facility to the Point of Interconnection.

ARTICLE 8. COMMUNICATIONS

8.1 Interconnection Customer Obligations

Interconnection Customer shall maintain satisfactory operating communications with Transmission Provider's Transmission System dispatcher or representative designated by Transmission Provider. Interconnection Customer shall provide, at its cost, standard voice line, dedicated voice line and facsimile communications at its Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide, at its cost, the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Provider as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Generating Facility to the location(s) specified by Transmission Provider. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 Remote Terminal Unit

Prior to the Initial Synchronization Date of the Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to both Parties, shall be installed by Interconnection Customer, or by Transmission Provider at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Provider through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Provider. Instantaneous bi-directional analog real power

Deleted: February 10, 2010.

and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Provider.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 No Annexation

Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

ARTICLE 9. OPERATIONS

9.1 General

Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 Operating Area Notification

At least three months before Initial Synchronization Date, the Interconnection Customer shall notify the Transmission Provider in writing of the Operating Area in which the Generating Facility will be located.

Deleted: February 10, 2010.

9.3 Transmission Provider Obligations

Transmission Provider shall cause the Transmission System and the Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this GIA. Transmission Provider may provide operating instructions to Interconnection Customer consistent with this GIA and Transmission Provider's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations

Interconnection Customer shall at its own expense operate, maintain and control the Generating Facility and the Interconnection Customer Interconnection Facilities in a safe and reliable manner and in accordance with this GIA. Interconnection Customer shall operate the Generating Facility and the Interconnection Customer Interconnection Facilities in accordance with all applicable requirements of the Operating Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this GIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Either Party may request that the other Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this GIA.

Except in an Emergency, the Interconnection Customer will request permission from the Transmission Provider's System Operator (or such Party designated by the System Operator) prior to opening or closing switching devices at the designated Point of Interconnection, identified in Appendix A of this GIA, in accordance with applicable switching and operations procedures, which permission will not be unreasonably withheld or delayed. If the Interconnection Customer opens or closes a switching device in an Emergency, without requesting permission from the System Operator, Interconnection Customer shall notify the System Operator immediately after taking such action.

Deleted: February 10, 2010.

The Interconnection Customer will carry out all switching orders from the System Operator in a timely manner.

9.5 Start-Up and Synchronization

Consistent with the Parties' mutually acceptable procedures, the Interconnection Customer is responsible for the proper synchronization of the Generating Facility to the Transmission Provider's Transmission System.

9.6 Reactive Power

9.6.1 Power Factor Design Criteria

Interconnection Customer shall design the Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Operating Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators. Instead, Appendix G sets forth specific requirements and provisions that apply to a wind Generating Facility.

9.6.2 Voltage Schedules

Once the Interconnection Customer has synchronized the Generating Facility with the Transmission System, Transmission Provider shall require Interconnection Customer to operate the Generating Facility to produce or absorb reactive power within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Provider's voltage schedules shall treat all sources of reactive power in the Operating Area in an equitable and not unduly discriminatory manner. Transmission Provider shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one day in advance, and may make changes to such schedules as necessary to maintain the

Deleted: February 10, 2010.

reliability of the Transmission System. Interconnection Customer shall operate the Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the System Operator.

9.6.2.1 Governors and Regulators

Whenever the Generating Facility is operated in parallel with the Transmission System and the speed governors (if installed on the generating unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, Interconnection Customer shall operate the Generating Facility with its speed governors and voltage regulators in automatic operation. If the Generating Facility's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Operating Area on a comparable basis.

9.6.3 Payment for Reactive Power

Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Generating

Deleted: February 10, 2010.

Facility only in those instances where the Transmission Provider requests the Interconnection Customer to operate its Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.

9.7 Outages and Interruptions

9.7.1 Outages

9.7.1.1 Outage Authority and Coordination

Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to both Parties. In all circumstances any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

9.7.1.2 Outage Schedules

The Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule

Deleted: February 10, 2010.

its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability.

9.7.1.3 Outage Restoration

If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 Interruption of Service

If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all Generating Facilities directly connected to the Transmission System;

Deleted: February 10, 2010.

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider shall coordinate with the Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to the Interconnection Customer and the Transmission Provider;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.2.6 If Transmission Provider determines that any of Interconnection Customer Interconnection Facilities or associated equipment fail to perform as designed, or that Interconnection Customer has failed to perform testing or maintenance of such equipment in accordance with the terms of this GIA and such failure has, or could reasonably be expected to adversely impact operation of the Transmission System, Transmission Provider shall notify Interconnection Customer in writing of such failure, its recommended corrective action, and its recommended deadline for the completion of such corrective actions. Within ten Business Days or the deadline reasonably specified by the Transmission Provider, Interconnection Customer must demonstrate to Transmission Provider's satisfaction that Interconnection

Deleted: February 10, 2010.

Customer has initiated such corrective action as is necessitated by Good Utility Practice. If Interconnection Customer fails to demonstrate within such time period to Transmission Provider's satisfaction that it has initiated or completed such corrective action as is necessitated by Good Utility Practice or that no corrective action is necessitated by Good Utility Practice, Transmission Provider may open the interconnection between Interconnection Customer and Transmission Provider; provided, however, that Transmission Provider may open the interconnection only for so long as is necessary under Good Utility Practice.

9.7.2.7 If Transmission provider determines that a modification to any of Interconnection Customer Interconnection Facilities or associated equipment has been made so that performance is not as originally approved by the Transmission Provider and such performance has, or could reasonably be expected to adversely impact operation of the Transmission System, Transmission Provider may, if such condition is not corrected after giving Interconnection Customer as much advance notice to correct the condition as is practicable under the circumstances, open the interconnection between Interconnection Customer and Transmission provider; provided, however, that Transmission Provider may open the interconnection only for so long as is necessary under Good Utility Practice.

9.7.2.8 Notwithstanding anything to the contrary in this Agreement, the Transmission Provider may immediately disconnect the Facility from the Transmission System, if the Transmission Provider perceives, consistent with Good Utility Practice, that the operation of the Interconnection Customer's equipment or Generating Facility presents an imminent threat to the reliable and safe operation of the Transmission System; provided, however that the Transmission provider may disconnect the facility for so long as is necessary under Good Utility Practice

Deleted: February 10, 2010.

9.7.3 Under-Frequency and Over Frequency Conditions

The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied by the Interconnection Customer and coordinated with the Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 System Protection and Other Control Requirements

9.7.4.1 System Protection Facilities

Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Generating Facility or the Interconnection Customer Interconnection Facilities. Transmission Provider shall install at Interconnection Customer's expense any System Protection Facilities that may be required on the Transmission Provider Interconnection Facilities or the Transmission System as a result of the interconnection of the Generating Facility and the Interconnection Customer Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

Deleted: February 10, 2010.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of the Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 Requirements for Protection

In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Generating Facility and

Deleted: February 10, 2010.

the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Generating Facility.

9.7.6 Power Quality

Each Party shall operate their facilities in such a manner so as to not cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by Applicable Standards adopted by the Transmission provider, such as Canadian Standards Association (CSA) CAN-C235-83, IEEE Recommended Practice 519 (Harmonics) and International Electrotechnical Commission (IEC) Flicker Standard 61000-3-7 (with Flicker Meter IEC 868 using a 120V, 60W weighting curve), or any applicable superseding electric industry standard, including the emission and quality limits specified in Appendix C Interconnection Details. In the event of a conflict between IEC Standard 61000-3-7, IEEE recommended Practice 519, CSA CAN-C235-83, or any applicable superseding electric industry standard, and the Appendix C Interconnection Details, the emission and quality limits specified in Appendix C, Interconnections Details, shall prevail.

9.8 Switching and Tagging Rules

Each Party shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

Deleted: February 10, 2010.

9.9 Use of Interconnection Facilities by Third Parties

9.9.1 Purpose of Interconnection Facilities

Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users

If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use the Transmission Provider's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to the Board for resolution.

9.10 Disturbance Analysis Data Exchange

The Parties will cooperate with one another in the analysis of disturbances to either the Generating Facility or the Transmission Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from

Deleted: February 10, 2010.

oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

9.11 Emergency Numbers

Each Party will provide, by written notice, an emergency telephone number, staffed 24 hours a day, to call in case of an emergency. Beginning of the Effective Date of this Agreement, and until modified in writing:

The Transmission Provider's emergency telephone numbers is: [INSERT NUMBER]
The Interconnection Customer's emergency telephone number is: [INSERT NUMBER]

9.12 Safety

Subject to Section 18, the Parties agree to be solely responsible for and assume all liability for the safety and supervision of their own employees, agents, representatives, and subcontractors.

The Parties agree that all work performed by either Party which could reasonably be expected to affect the operations of the other Party will be performed in accordance with all applicable laws, rules, and regulations pertaining to the safety of persons or property, including without limitation, compliance with the safety regulations and standards adopted under the Occupational Health and Safety Act, as amended from time to time, the Canadian Electrical Safety Code as amended from time to time and Good Utility Practice.

ARTICLE 10. MAINTENANCE

10.1 Transmission Provider Obligations

Transmission Provider shall maintain the Transmission System and the Transmission Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA.

Deleted: February 10, 2010.

10.2 Interconnection Customer Obligations

Interconnection Customer shall maintain the Generating Facility and the Interconnection Customer Interconnection Facilities in a safe and reliable manner and in accordance with this GIA.

10.3 Coordination

The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Generating Facility and the Interconnection Facilities.

10.4 Secondary Systems

Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 Operating and Maintenance Expenses

Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with:

Deleted: February 10, 2010.

(1) owning, operating, maintaining, repairing, and replacing Interconnection Customer Interconnection Facilities; and

(2) operation, maintenance, repair and replacement of Transmission Provider's Interconnection Facilities.

ARTICLE 11. PERFORMANCE OBLIGATION

11.1 Interconnection Customer Interconnection Facilities

Interconnection Customer shall design, procure, construct, install, own and operate the Interconnection Customer Interconnection Facilities described in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades), at its sole expense.

11.2 Transmission Provider's Interconnection Facilities

Unless otherwise agreed pursuant to Section 5.1.3, Transmission Provider or Transmission Owner shall design, procure, construct, install, own and operate the Transmission Provider's Interconnection Facilities described in Appendix A, (Interconnection Facilities, Network Upgrades and Distribution Upgrades), at the sole expense of the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades

Transmission Provider or Transmission Owner shall design, procure, construct, install, own and operate the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless the Transmission Provider or Transmission Owner elects to fund the capital for the Network Upgrades, they shall be solely funded by the Interconnection Customer.

Deleted: February 10, 2010.

11.4 Transmission Credits

11.4.1 Refund of Amounts Advanced for Network Upgrades

Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Generating Facility.

If, after the effective date of this revised GIP, the Interconnection Customer establishes a contract for sale of the output of the Generating Facility to a Load Serving Entity and there are otherwise no incremental payments for transmission service resulting from the use of the Generating Facility by the Load Serving Entity, and in the absence of another mutually agreeable payment schedule, any repayments provided under this Article 11.4.1 shall be established equal to the applicable charge for Long-Term Firm and Short-Term Firm Point-To-Point transmission service defined under Schedule 7 (section 1, 2, 3 or 5, as applicable) of the Tariff multiplied by the portion of the demonstrated output of the Generating Facility under contract to the Load Serving Entity.

Any repayment shall include interest from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date:

Deleted: February 10, 2010.

(1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or

(2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides return of all amounts advanced for Network Upgrades not previously repaid; however full reimbursement shall not extend beyond (20) years from the Commercial Operation Date

If the Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and Affected System Operator shall at that time reimburse the Transmission Provider for the amounts advanced for the Network Upgrades.

Before such re-imbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the generating facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 Refund of Amounts Advanced for Network Upgrades for Renewable to Retail Generating Facilities

Section 11.4.1 shall not apply to Network Upgrades made in respect of an Interconnection Customer's Generating Facility which has been designated as a Network Resource by a Licensed Retail Supplier for the purpose of supplying renewable low-impact electricity to Retail Customers pursuant to the *Electricity Act*, S.N.S. 2004, c. 25.

If, after the effective date of this revised GIP, any portion of a Generating Facility's

Deleted: February 10, 2010.

capacity is designated as a Network Resource by a Licensed Retail Supplier for the purpose of supplying renewable low-impact electricity to Retail Customers pursuant to the *Electricity Act* ("Designated Generating Facility"), the Interconnection Customer shall at that time promptly reimburse the Transmission Provider for amounts previously repaid by the Transmission Provider based on the pro rata portion of the Designated Generating Facility's capacity. Any such repayment amounts owing by the Transmission Provider to the Interconnection Customer will be reduced based on the pro rata portion of the Designated Generating Facility's capacity.

11.5 Provision of Security

At least 30 Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of a Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the applicable laws of Nova Scotia. Such security for payment shall be in an amount sufficient to cover the costs for constructing, procuring and installing the applicable portion of Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider under this GIA during its term.

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

Deleted: February 10, 2010.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.6 Interconnection Customer Compensation

If Transmission Provider requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this GIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to Board-approved rate schedule. Interconnection Customer shall serve Transmission Provider with any filing of a proposed rate schedule at the time of such filing with the Board. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this GIA, the Transmission Provider agrees to compensate the Interconnection Customer in such amount as would have been due the Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed with the Board or other appropriate Governmental Authority within 60 Calendar Days of the commencement of service.

11.6.1 Interconnection Customer Compensation for Actions During Emergency Condition

Transmission Provider shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.6.

ARTICLE 12. INVOICE

Deleted: February 10, 2010.

12.1 General

Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this GIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice

Within six months after completion of the construction of the Transmission Provider's Interconnection Facilities and the Network Upgrades, Transmission Provider shall provide an invoice of the final cost of the construction of the Transmission Provider's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within 30 Calendar Days of the issuance of such final construction invoice.

12.3 Payment

Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within 30 Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by Interconnection Customer will not constitute a waiver of any rights or claims Interconnection Customer may have under this GIA.

Deleted: February 10, 2010.

12.4 Disputes

In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide Interconnection Service under this GIA as long as Interconnection Customer:

(i) continues to make all payments not in dispute; and

(ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute.

If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within 30 Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest.

ARTICLE 13. EMERGENCIES

13.1 Definition

"Emergency Condition" shall mean a condition or situation:

(i) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or

(ii) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, the Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or

Deleted: February 10, 2010.

(iii) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to**,** the Generating Facility or the Interconnection Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this GIA to possess black start capability.

13.2 Obligations

Each Party shall comply with the Emergency Condition procedures of the Applicable Reliability Council, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

13.3 Notice

Transmission Provider shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects the Transmission Provider's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Generating Facility or the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider promptly when it becomes aware of an Emergency Condition that affects the Generating Facility or the Interconnection Customer Interconnection Facilities that may reasonably be expected to affect the Transmission System or the Transmission Provider's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Provider's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

13.4 Immediate Action

Deleted: February 10, 2010.

Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Provider, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Generating Facility or the Interconnection Customer Interconnection Facilities in response to an Emergency Condition either declared by the Transmission Provider or otherwise regarding the Transmission System.

13.5 Transmission Provider Authority

13.5.1 General

Transmission Provider may take whatever actions or inactions with regard to the Transmission System or the Transmission Provider's Interconnection Facilities it deems necessary during an Emergency Condition in order to

(i) preserve public health and safety,

(ii) preserve the reliability of the Transmission System or the Transmission Provider's Interconnection Facilities,

(iii) limit or prevent damage, and

(iv) expedite restoration of service.

Transmission Provider shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Generating Facility or the Interconnection Customer Interconnection Facilities. Transmission Provider may, on the basis of technical considerations, require the Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Generating Facility; implementing a reduction or disconnection pursuant to Article

Deleted: February 10, 2010.

13.5.2; directing the Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Generating Facility and the Interconnection Customer Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's operating instructions concerning Generating Facility real power and reactive power output within the manufacturer's design limitations of the Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 Reduction and Disconnection

Transmission Provider may reduce Interconnection Service or disconnect the Generating Facility or the Interconnection Customer Interconnection Facilities when such reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of the Transmission Provider pursuant to the Transmission Provider's Tariff. When the Transmission Provider can schedule the reduction or disconnection in advance, Transmission Provider shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider shall coordinate with the Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to the Interconnection Customer and the Transmission Provider. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.6 Interconnection Customer Authority

Consistent with Good Utility Practice and the GIA and the GIP, the Interconnection Customer may take whatever actions or inactions with regard to the Generating Facility or

Deleted: February 10, 2010.

the Interconnection Customer Interconnection Facilities during an Emergency Condition in order to

(i) preserve public health and safety,

(ii) preserve the reliability of the Generating Facility or the Interconnection Customer Interconnection Facilities,

(iii) limit or prevent damage, and

(iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and the Transmission Provider's Interconnection Facilities.

Transmission Provider shall use Reasonable Efforts to assist Interconnection Customer in such actions. Interconnection Customer shall not be obligated to follow Transmission Provider's instructions to the extent the instruction would have a material adverse impact on the safe and reliable operation of Interconnection Customer's Generating Facility. Upon request, Interconnection Customer shall provide Transmission Provider with documentation of any such alleged material adverse impact.

13.7 Limited Liability

Except as otherwise provided in Article 11.6.1 of this GIA, neither Party shall be liable to the other for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

ARTICLE 14. REGULATORY REQUIREMENTS AND GOVERNING LAW

14.1 Regulatory Requirements

Deleted: February 10, 2010.

Each Party's obligations under this GIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such approvals.

14.2 Applicable Law

14.2.1 This Agreement shall be governed by and interpreted in accordance with the laws of the Province of Nova Scotia.

ARTICLE 15. NOTICES

15.1 General

Unless otherwise provided in this GIA, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the Canada Post Corporation with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Either Party may change the notice information in this GIA by giving five Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments

Billings and payments shall be sent to the addresses set out in Appendix F.

Deleted: February 10, 2010.

15.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by either Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice

Each Party shall notify the other Party in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

ARTICLE 16. FORCE MAJEURE

16.1 Force Majeure

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this Article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede

Deleted: February 10, 2010.

or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

ARTICLE 17. DEFAULT

17.1 Default

17.1.1 General

No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this GIA or the result of an act or omission of the other Party. Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in Article 17.1.2, the defaulting Party shall have 30 Calendar Days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 30 Calendar Days, the defaulting Party shall commence such cure within 30 Calendar Days after notice and continuously and diligently complete such cure within 90 Calendar Days from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

17.1.2 Right to Terminate

If a Default is not cured as provided in this Article, or if a Default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate this GIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this GIA, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this Article will survive termination of this GIA.

Deleted: February 10, 2010.

ARTICLE 18. INDEMNITY, CONSEQUENTIAL DAMAGES AND INSURANCE

18.1 Indemnity

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions arising from its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

18.1.1 Indemnified Person

If an indemnified person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 Indemnifying Party

If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 18, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

Deleted: February 10, 2010.

18.1.3 Indemnity Procedures

Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party

(i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between theindemnified person and the indemnifying Party,

Deleted: February 10, 2010.

in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and

(ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be unreasonably withheld, conditioned or delayed.

18.2 Consequential Damages

Other than the liquidated damages heretofore described, in no event shall either Party be liable under any provision of this GIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance

Each party shall, at its own expense, maintain in force throughout the period of this GIA, and until released by the other Party, the following minimum insurance coverages, with insurers licensed to do business in Nova Scotia.

18.3.1 Each party shall provide a copy of a certificate of registration, affidavit, or letter of compliance from the Nova Scotia Workers' Compensation Board.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent

Deleted: February 10, 2010.

normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of Ten Million Dollars ($10,000,000) per occurrence/Ten Million Dollars ($10,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of Two Million Dollars ($2,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this GIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

Deleted: February 10, 2010.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two years after termination of this GIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this GIA.

18.3.9 Within ten days following execution of this GIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within 90 days thereafter, each Party shall provide certification of all insurance required in this GIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade, or better, by a rating agency acceptable to the Transmission Provider. For any period of time that a Party's senior secured debt is unrated or is rated at less than investment grade, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.1 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this Article 18.3.10, it shall not be required to comply with the insurance requirements applicable to it under Articles 18.3.1 through 18.3.9. In the event that a Party is permitted to self-insure, such Party shall provide satisfactory evidence on a quarterly basis that its senior secured debt maintains a rating of investment grade or better, that such rating is not under review by the rating agency, and that the Party is not aware of any circumstance that would cause such rating to fall below investment grade.

Deleted: February 10, 2010.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this GIA.

18.4 Duty to Mitigate

Each Party has a duty to mitigate damages and shall use all reasonable efforts to minimize any losses, costs, expenses, damages or other liabilities it may incur as a result of the other Party's performance or non-performance of this Agreement, but for greater certainty, neither Party shall have any duty to mitigate damages or losses for which this Agreement provides specific compensation.

ARTICLE 19. ASSIGNMENT

19.1 Assignment

This GIA may be assigned by either Party only with the written consent of the other; provided that either Party may assign this GIA without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this GIA; and provided further that the Interconnection Customer shall have the right to assign this GIA, without the consent of the Transmission Provider, for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that violates this Article is void and ineffective. Any assignment under this GIA shall not relieve a Party of its obligations, nor shall a Party's obligations be

Deleted: February 10, 2010.

enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

ARTICLE 20. SEVERABILITY

20.1 Severability

If any provision in this GIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this GIA; provided that if the Interconnection Customer (or any third party, but only if such third party is not acting at the direction of the Transmission Provider) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

ARTICLE 21. COMPARABILITY

21.1 Comparability

The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

ARTICLE 22. CONFIDENTIALITY

22.1 Confidentiality

A Party providing Confidential Information shall notify, either orally or in writing, the Party receiving the information, that the information provided is confidential.

Deleted: February 10, 2010.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that Confidential Information warrants confidential treatment. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term

During the term of this GIA, and for a period of three years after the expiration or termination of this GIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 Scope

Confidential Information shall not include information that the receiving Party can demonstrate:

(1) is generally available to the public other than as a result of a disclosure by the receiving Party;

(2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party;

(3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential;

(4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party;

(5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this GIA; or

Deleted: February 10, 2010.

(6) is required, in accordance with Article 22.1.7 of the GIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this GIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 Release of Confidential Information

Neither Party shall release or disclose Confidential Information to any other person, except to its employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this GIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any subsequent release of Confidential Information in contravention of this Article 22.

22.1.4 Rights

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 No Warranties

Deleted: February 10, 2010.

By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 Standard of Care

Each Party shall use at least the same standard of care to protect the other Party's Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use the other Party's Confidential Information solely to fulfill its obligations to the other Party under this GIA or its regulatory requirements.

22.1.7 Order of Disclosure

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this GIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 Termination of Agreement

Upon termination of this GIA for any reason, each Party shall, within ten Calendar Days of receipt of a written request from the other Party, use Reasonable Efforts to

Deleted: February 10, 2010.

destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 Remedies

The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 Disclosure to The Board or its Staff

Notwithstanding anything in this Article 22 to the contrary, if the Board or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this GIA, the Party shall provide the requested information to the Board or its staff, within the time provided for in the request for information. In providing the information to the Board or its staff, the Party must, request that the information be treated as confidential and non-public by the Board and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this GIA prior to the release of the Confidential

Deleted: February 10, 2010.

Information to the Board or its staff. The Party shall notify the other Party to the GIA when it is notified by the Board or its staff that a request to release Confidential Information has been received by the Board, at which time either of the Parties may respond before such information would be made public.

22.1.11 Subject to the exceptions in Article 22.1.3 and Article 22.1.10, any information that a Party claims is Confidential Information shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is

(i) required by law;

(ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute;

(iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or

(iv) necessary to fulfill its obligations under this GIA or as a transmission service provider or an Operating Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization.

Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

Deleted: February 10, 2010.

22.1.12 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

ARTICLE 23. ENVIRONMENTAL RELEASES

23.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall:

(i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and

(ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

ARTICLE 24. INFORMATION REQUIREMENTS

24.1 Information Acquisition

Transmission Provider and the Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 Information Submission by Transmission Provider

The initial information submission by Transmission Provider shall occur no later than 180 Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow the Interconnection Customer to select equipment and meet any system

Deleted: February 10, 2010.

protection and stability requirements, unless otherwise mutually agreed to by both Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information:

(1) progress to date;

(2) a description of the activities since the last report

(3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 Updated Information Submission by Interconnection Customer

The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than 180 Calendar Days prior to the Trial Operation. Interconnection Customer shall submit a completed copy of the Generating Facility data requirements contained in Appendix 1 to the GIP. It shall also include any additional information provided to Transmission Provider for the Feasibility and Facilities Study. Information in this submission shall be the most current Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreement between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on the Transmission Provider Transmission System based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

Deleted: February 10, 2010.

24.4 Information Supplementation

Prior to the Commercial Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all “as-built” Generating Facility information or “as-tested” performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Generating Facility as required by Good Utility Practice such as an open circuit “step voltage” test on the Generating Facility to verify proper operation of the Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include:

(1) Generating Facility at synchronous speed;

(2) automatic voltage regulator on and in voltage control mode; and

(3) a five percent (5 percent) change in Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage.

Interconnection Customer shall provide validated test recordings showing the responses of Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Generating Facility’s terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Generating Facility terminal or field voltages is provided. Generating Facility testing shall be conducted and results provided to the Transmission Provider for each individual generating unit in a station.

Subsequent to the Commercial Operation Date, the Interconnection Customer shall provide Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Provider shall provide the Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Provider-owned substation that may

Deleted: February 10, 2010.

affect the Interconnection Customer Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than 30 Calendar Days after the date of the equipment replacement, repair or adjustment.

ARTICLE 25. INFORMATION ACCESS AND AUDIT RIGHTS

25.1 Information Access

Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to:

(i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this GIA; and

(ii) carry out its obligations and responsibilities under this GIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this GIA.

25.2 Reporting of Non-Force Majeure Events

Each Party (the "notifying Party") shall notify the other Party when the notifying Party becomes aware of its inability to comply with the provisions of this GIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, and reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this GIA.

Deleted: February 10, 2010.

25.3 Audit Rights

Subject to the requirements of confidentiality under Article 22 of this GIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this GIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, the Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, the Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this Article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this GIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods

25.4.1 Audit Rights Period for Construction-Related Accounts and Records

Accounts and records related to the design, engineering, procurement, and construction of Transmission Provider's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Provider's issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records

Accounts and records related to either Party's performance or satisfaction of all obligations under this GIA other than those described in Article 25.4.1 shall be subject to audit as follows:

Deleted: February 10, 2010.

(i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and

(ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

25.5 Audit Results

If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

ARTICLE 26. SUBCONTRACTORS

26.1 General

Nothing in this GIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this GIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this GIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 Responsibility of Principal

The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this GIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under Article 5 of this GIA. Any applicable

Deleted: February 10, 2010.

obligation imposed by this GIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance

The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

ARTICLE 27. DISPUTES

27.1 External Arbitration Procedures

In the event of a dispute arising between the Parties as to the subject matter of this Agreement that cannot be resolved between them, the Parties agree to submit the dispute to binding arbitration, pursuant to the terms of the *Commercial Arbitration Act*, S.N.S. 1999, c.5. In particular, the Parties agree to utilize the arbitration procedure attached as Schedule "A" to the *Commercial Arbitration Act* in the conduct of the arbitration. Any matter in dispute that is submitted for arbitration shall be heard by a single arbitrator chosen unanimously by the parties. In the event the parties cannot agree on a person to act as a single arbitrator, each party shall choose one panelist and the two panelists shall choose an independent third panelist who shall also chair the arbitration. No such arbitrator shall have previously been employed by either party and shall not have a direct or indirect interest in either party or the subject matter of the arbitration. The cost of the arbitration, excluding a parties legal fees and disbursements shall, unless otherwise ordered by the arbitrator or the panel, be borne equally by the parties.

27.2 Arbitration Decisions

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within 90 Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this GIA and shall have no power to modify or change any provision of this

Deleted: February 10, 2010.

Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction.

ARTICLE 28. REPRESENTATIONS, WARRANTIES AND COVENANTS

28.1 General

Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing

Such Party is duly organized, validly existing and in good standing under the laws of the jurisdiction in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the Province or Provinces in which the Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located**;** and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this GIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this GIA.

28.1.2 Authority

Such Party has the right, power and authority to enter into this GIA, to become a Party hereto and to perform its obligations hereunder. This GIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

Deleted: February 10, 2010.

28.1.3 No Conflict

The execution, delivery and performance of this GIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets

28.1.4 Consent and Approval

Such Party has sought or obtained, or, in accordance with this GIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this GIA, and it will provide to any Governmental Authority notice of any actions under this GIA that are required by Applicable Laws and Regulations.

ARTICLE 29. JOINT OPERATING MEETINGS

29.1 Joint Operating and Maintenance Meetings

Transmission Provider shall constitute a Joint Operating and Maintenance Meeting to coordinate operating and technical considerations of Interconnection Service. At least six months prior to the expected Initial Synchronization Date, Interconnection Customer and Transmission Provider shall each appoint one representative and one alternate to hold an initial Operating and Maintenance Meeting. Each Party shall notify the other Party of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating and Maintenance Meeting shall be conducted as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Parties shall hold a meeting at the request of either Party, at a time and place agreed upon by the representatives. All decisions and agreements, if any, made by the Joint Operating and Maintenance Meetings shall be documented in Minutes. The objectives of the Joint Operating and Maintenance Meetings shall include the following:

Deleted: February 10, 2010.

29.1.1 To establish data requirements and operating record requirements.

29.1.2 To review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

29.1.3 Annually review the one year forecast of maintenance and planned outage schedules of Transmission Provider's and Interconnection Customer's facilities at the Point of Interconnection.

29.1.4 To coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Generating Facility and other facilities that impact the normal operation of the interconnection of the Generating Facility to the Transmission System.

29.1.5 To ensure that information is being provided by each Party regarding equipment availability.

29.1.6 To perform such other duties as may be conferred upon it by mutual agreement of the Parties.

29.1.7 To establish and maintain control and operating procedures, including those pertaining to information transfers between the Generating facility and the Transmission Provider.

ARTICLE 30. MISCELLANEOUS

30.1 Binding Effect

This GIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts

Deleted: February 10, 2010.

In the event of a conflict between the body of this GIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this GIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation

This GIA, unless a clear contrary intention appears, shall be construed and interpreted as follows:

(1) the singular number includes the plural number and vice versa;

(2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this GIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually;

(3) reference to any agreement (including this GIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof;

(4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder;

(5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this GIA or such Appendix to this GIA, or such Section to the GIP or such Appendix to the GIP, as the case may be;

Deleted: February 10, 2010.

(6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this GIA as a whole and not to any particular Article or other provision hereof or thereof;

(7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and

(8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 Entire Agreement

This GIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this GIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this GIA.

30.5 No Third Party Beneficiaries

This GIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver

The failure of a Party to this GIA to insist, on any occasion, upon strict performance of any provision of this GIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Deleted: February 10, 2010.

Any waiver at any time by either Party of its rights with respect to this GIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this GIA. Termination or Default of this GIA for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this GIA shall, if requested, be provided in writing.

30.7 Headings

The descriptive headings of the various Articles of this GIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this GIA.

30.8 Multiple Counterparts

This GIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment

The Parties may by mutual agreement amend this GIA by a written instrument duly executed by both of the Parties.

30.10 Modification by the Parties

The Parties may by mutual agreement amend the Appendices to this GIA by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this GIA upon satisfaction of all Applicable Laws and Regulations.

Deleted: February 10, 2010.

30.11 No Partnership

This GIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

[THE REMAINDER OF THIS PAGE IS INTENTIONALLY BLANK]

Deleted: February 10, 2010.

IN WITNESS WHEREOF, the Parties have executed this GIA in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ______________________ By: ______________________

Title: ______________________ Title: ______________________

Date: ______________________ Date: ______________________

[Insert name of Interconnection Customer]

By: ______________________

Title: ______________________

Date: ______________________

Deleted: February 10, 2010.

Appendix A
To GIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. Interconnection Facilities:

[Identify the Point of Interconnection]

[Identify the Point of Change of Ownership]

(a) [insert Interconnection Customer's Interconnection Facilities]:

(b) [insert Transmission Provider's Interconnection Facilities]:

2. Network Upgrades:

(a) [insert Stand Alone Network Upgrades]:

(b) [insert Other Network Upgrades]:

3. Distribution Upgrades:

[THE REMAINDER OF THIS PAGE IS INTENTIONALLY BLANK]

Appendix B
To GIA

Milestones

Provision of Security Date (per Section 11.5):

Design and Procurement Authorization Date (per Article 5.5.2):

Construction Authorization Date (per Article 5.6.3):

In-Service Date:

Initial Synchronization Date:

Commercial Operation Date:

Construction Option:

[THE REMAINDER OF THIS PAGE IS INTENTIONALLY BLANK]

Appendix C
To GIA

Interconnection Details

Schedule A to Appendix C

Basic One Line

Schedule B to Appendix C

Interconnection Facilities Report

Appendix D
To GIA

Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. The Board will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with best practice recommendations from the Applicable Reliability Council and NERC (North American Reliability Corporation). All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

[THE REMAINDER OF THIS PAGE IS INTENTIONALLY BLANK]

Appendix E

To GIA

Initial Synchronization Date and Commercial Operation Date

This Appendix E is a part of the GIA between Transmission Provider and Interconnection Customer, and is to be submitted 24hrs prior to the Initial Synchronization Date to confirm the date on which the Trial Operation of the unit at the Generating Facility is expected to begin and again within 24hrs of the Commercial Operation Date to confirm the completion of the Trial Operation and the date on which commercial operation of such unit commenced.

[Date]

[Transmission Provider Address]

Re: _____________ Generating Facility

Dear _____________:

On **[Date], [Interconnection Customer]** expects to begin Trial Operation of Unit No. ___at the Generating Facility.

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. ___. This letter confirms that [Interconnection Customer] commenced commercial operation of Unit No. ___________ at the Generating Facility, effective as of **[Date plus one day]**.

Thank you.

[Signature]

[Interconnection Customer Representative]

Appendix F
To GIA

Addresses for Delivery of Notices and Billings

Notices:.

Transmission Provider:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Billings and Payments:

Transmission Provider:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

APPENDIX G

To GIA

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this GIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below.

LVRT Standard

All wind generating plants must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind generating plant step-up transformer (“GSU”). For the purposes of Appendix G, “GSU” shall mean Interconnection Customer’s Interconnection Facilities substation transformer.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. Power Factor Design Criteria (Reactive Power)

A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this GIA. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

[THE REMAINDER OF THIS PAGE IS INTENTIONALLY BLANK]

APPENDIX H

To GIA

REGULATORY AND GOVERNMENT AGENCY APPROVALS

The Interconnection Customer shall be solely responsible to obtain any and all permits and approvals (such as regulatory environmental approvals both federal and provincial) that (1) it requires to lawfully construct, own and operate the Generating Facility and the Interconnection Customer's Interconnection Facilities and (2) are required to lawfully construct the Transmission Provider's Interconnection Facilities.

The Transmission Provider shall be solely responsible to obtain any and all permits and approvals that (1) it requires to lawfully own and operate the Transmission Provider's Interconnection Facilities and (2) it requires to lawfully construct, own and operate any and all Network Upgrades and (3) it requires to lawfully construct modifications to (as may be contemplated in this Agreement), own and operate the Transmission System.

[THE REMAINDER OF THIS PAGE IS INTENTIONALLY BLANK]