Nova Scotia Power
Final Pre-IRP Report

October 18, 2019

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Nova Scotia Power Final Pre-IRP Deliverables Report

1. Introduction

In its letter dated October 5, 2018[1], the Nova Scotia Utility and Review Board (NSUARB, Board) directed Nova Scotia Power (NS Power, the Company) to undertake an Integrated Resource Plan (IRP) process for completion by mid-2020, and to aim to complete the "pre-IRP analyses" (recommended by the Generation Utilization and Optimization report by Synapse Energy Economics, Inc. (Synapse) and the Bates White Economic Consulting (Bates White) report dated July 24, 2018 from its audit of the Fuel Adjustment Mechanism for 2016-2017) by July 31, 2019.

In advance of completing this work and with the intent of informing the 2020 IRP analysis and laying the foundation for broad stakeholder engagement throughout the process, the Company undertook to engage with IRP stakeholders on IRP fundamentals and the initial results of these studies. The result of that work and the associated documents and information exchanged among the parties is provided with this Report with the intention that it will support development of a complete record of this IRP proceeding and serve to inform development of the 2020 IRP Terms of Reference (TOR).

NS Power's letter of May 17, 2019[2] to the UARB outlined four "pre-IRP deliverables" developed to address the Board's direction. On July 31, 2019 the Company circulated the four draft deliverables to parties who had expressed interest in the IRP process:

1. Capacity Study	2. Supply Options Study	3. Renewables Stability Study	4. Demand Response Assumptions
A "Capacity Study" which used the loss of load expectation (LOLE) methodology to establish planning reserve margin, capacity value of wind, and battery storage duration requirements.	*A "Supply Options Study" which proposed cost assumptions for new supply-side options and provided the current forecasted sustaining capital costs for existing supply-side units.*	*The "Stability Study for Renewables Integration" which assessed transmission requirements for increased levels of renewables on the Nova Scotia system.*	*The "Demand Response Assumptions" which proposed estimated program costs and peak load impact for specific demand response (DR) activities.*

NS Power has continuously engaged with stakeholders throughout the pre-IRP process, as detailed in Section 2. Report overviews and summaries of findings were presented to IRP participants in Pre-IRP Technical Conferences discussed below by NS Power IRP leads and the report authors. The materials from these workshops are provided in Attachments 3 to 6.

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[1] Attachment 1, NSUARB letter to Nova Scotia Power re: IRP and Generation Utilization and Optimization (M08059), October 5 2018

[2] Attachment 2, Nova Scotia Power letter to NSUARB re: NS Power 2020 IRP and Pre-IRP Workshops

Outside of the broad stakeholder sessions, the Company received questions and submissions from the Small Business Advocate (SBA), Bates White (consultant for the UARB), EfficiencyOne (E1), Energy Futures Group (consultant for E1), Envigour, the Verschuren Centre, and the Alternative Resource Energy Authority (AREA). These submissions are provided in Attachments 7 to 13, respectively. NS Power conducted individual meetings as required to discuss the questions from these parties which were not addressed in the broader workshops. The responses to these early questions and/or comments are included in Appendix A.

Following this ongoing engagement and the final pre-IRP workshop held August 27, 2019, the Company requested written feedback from interested parties on the four pre-IRP deliverables by September 13, 2019. Submissions on the deliverables were provided by Bates White, the SBA, and AREA (provided in Attachments 14 to 16). Section 3 below provides NS Power's response to these submissions; detailed technical responses to all individual questions and comments is also included in Appendix A.

As described in Section 3, NS Power is confident that the feedback received from stakeholders on the Pre-IRP Deliverables can be incorporated in the broader IRP process, specifically in the Analysis Plan Development, Assumptions Development, and Modeling phases. Accordingly, NS Power has attached the final versions of the four Pre-IRP Deliverables to this report (Attachments 17 to 20). The Company expects to next begin development on the Terms of Reference (TOR) in order to establish the IRP objectives and outline the major milestones for the process leading to the mid-2020 completion.

NS Power would like to thank all IRP participants for their interest and contributions to date. The Company will work with interested parties to incorporate their feedback into the upcoming project phases and looks forward to continuing this ongoing engagement throughout the IRP process.

2. Pre-IRP Stakeholder Engagement

NS Power began to engage with interested parties in May 2019 to discuss the IRP process, key issues, and the status and results of the pre-IRP deliverables. The Company has held one teleconference and three in-person half-day workshops (the materials from each of these, as well as multiple one-on-one meetings with stakeholders to discuss questions and comments. The pre-IRP engagement activities are summarized in **Figure 1** below.

Figure 1: Pre-IRP 2019 Stakeholder Engagement Activities

Date	Stakeholder(s)	Description	Topics
24-May	All IRP Interested Parties	Teleconference	Overview of Pre-IRP Deliverables
13-Jun	Ecology Action Centre	One-on-one (Meeting)	General
18-Jun	EfficiencyOne	One-on-one (Teleconference)	General
25-Jun	CanWEA	One-on-one (Teleconference)	General
28-Jun	All IRP Interested Parties	Workshop	IRP Background, Industry Trends, Evolution of Planning, Pre-IRP Work Update, E1 Potential Study Update
28-Jun	AREA	One-on-one (Meeting)	General
9-Jul	HRM	One-on-one (Meeting)	General
6-Aug	EfficiencyOne	One-on-one (Teleconference)	General
7-Aug	All IRP Interested Parties	Workshop	Results and Q&A on Capacity Study and Supply Options Study, Introduction to Stability Study for Renewables Integration
8-Aug	AREA	Submission of Questions	General
8-Aug	Envigour	Submission of Questions	General
21-Aug	Envigour	Submission of Material	Renewable Power Cost source information for consideration
23-Aug	AREA	One-on-one (Teleconference)	General
23-Aug	Envigour & NS Department of Energy	One-on-one (Teleconference)	General
26-Aug	Bates White (Board Consultant)	Submission of Questions	General
26-Aug	Verschuren Centre	Submission of Questions	General
26-Aug	EfficiencyOne	Submission of Questions	General
27-Aug	All IRP Interested Parties	Workshop	Results of Stability Study for Renewables Integration, Q&A on all Pre-IRP Deliverables
28-Aug	Energy Futures Group (E1 consultant)	Submission of Questions	General
3-Sep	Veruschen Centre	One-on-one (Meeting)	General
5-Sep	EfficiencyOne & Energy Futures Group	One-on-one (Meeting)	General

6-Sep	Bates White (Board Consultant)	One-on-one (Teleconference)	General
12-Sep	AREA	Submission of Questions/Comments	General
12-Sep	Bates White	Submission of Questions/Comments	General
13-Sep	SBA	Submission of Questions/Comments	General
18-Sep	EfficiencyOne & Energy Futures Group	One-on-one (Meeting)	General

Attachments 3 through 6 provide the materials issued for the four Pre-IRP workshops by NS Power. The Company's responses to the stakeholder submissions listed above are provided in Section 3 and the detailed technical replies to questions and comments are detailed in Appendix A.

NS Power plans to continue extensive stakeholder engagement throughout the IRP process. In order to help facilitate communication throughout this process, the Company has launched an IRP website (irp.nspower.ca) which it plans to use as repository for documentation as well as a tool for gathering stakeholder feedback.

3. Response to Stakeholder Feedback & Inquiries

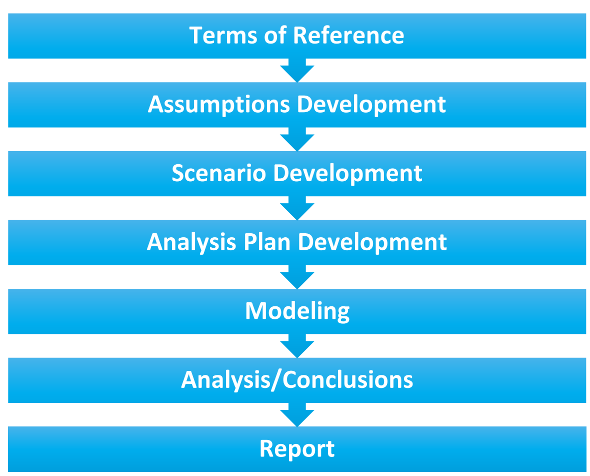
The following sections summarize NS Power's responses to stakeholder comments on the Pre-IRP Deliverables, and provide clarity on how these considerations fit within the context of the broader IRP process.

3.1 Overview: The IRP Process

The 2020 Integrated Resource Planning process is the fourth Integrated Resource Planning exercise undertaken by NS Power and stakeholders since 2007. Building on process improvements developed over this period and recognising the increasingly dynamic and complex resource planning environment facing electric utilities today, the 2020 IRP will follow a transparent, collaborative and disciplined approach in order to provide direction and inform the strategy for Nova Scotia's energy future. The industry-leading modeling processes to be employed will establish optimized resource portfolios (i.e. an economic selection of demand side and supply side resources) for a range of foreseeable futures (i.e. "worlds" or "scenarios") for NS Power and will evaluate the relative merits of these portfolios based on criteria established for the IRP process.

Figure 2 below illustrates the main phases typically undertaken during IRP processes in Nova Scotia to date. Each of these phases will be conducted in consultation with stakeholders; for example, Draft Assumptions will be issued for stakeholder feedback, followed by revisions and issuance of Final Assumptions for use in the modeling.

Figure 2: Phases of the IRP Process

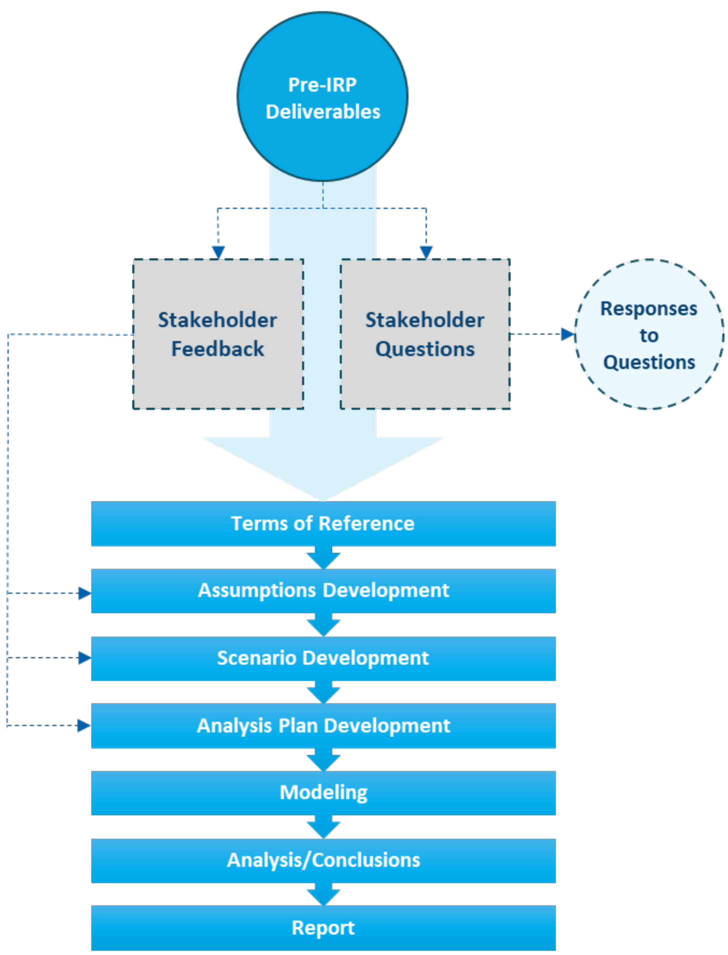


Evaluating options across a range of potential future scenarios is particularly relevant in today's planning environment where we face significant uncertainty across virtually all key planning areas including federal/provincial energy policy, future technology pricing and operating characteristics, customer demand, and emerging market trends (such as electrification and distributed energy resources).

Given this level of uncertainty and the interplay of these key areas, an important exercise during this IRP will be identifying signposts (i.e. items to monitor) which could indicate or trigger a material change in strategic direction and/or the optimal path forward. In order to identify these signposts, a critical element of the portfolio modeling will be evaluating the impact of major changes in the underlying assumptions; in particular, the "bookends" (i.e. significantly high or low cases compared to the expected values).

The Pre-IRP Deliverables provide starting points for determining the expected value (i.e. "base case") of many of the IRP assumptions. In previous IRP exercises in Nova Scotia, these details were not provided or examined until the Draft Assumptions Phase (e.g. prices for new supply side resources, capacity value of renewables, planning reserve margin, etc.). The prework completed for the 2020 IRP has enabled deeper engagement at an early phase and will allow the Company to continue to consult with interested parties to refine these assumptions earlier than has been typically possible in past IRP exercises, as illustrated in **Figure 3**.

Figure 3: Addressing Stakeholder Feedback



Some of the questions posed regarding the Pre-IRP deliverables are not applicable to the pre-work studies but will be addressed through later phases in the IRP. For example, the Pre-IRP deliverables do not address commercial considerations such as economic dispatch or contractual options; many of these issues are at the core of the work to come in the IRP Modeling Phase where portfolios are optimized based on economics and system constraints. The Analysis Plan may also identify other metrics for consideration in evaluating the optimal path forward that will be considered during the Modeling and/or Analysis/Conclusions Phases.

Many of the remaining assumptions which stakeholders have inquired about in their submissions to date (e.g. fuel prices, transmission/import options, distributed energy resources, demand side programs, etc.) are currently under development and will be issued during the Assumptions Development Phase for further discussion and refinement. Similarly, the “bookend” sensitivity cases for critical assumptions will be proposed at that time in draft for review and discussion.

A critical phase in the initiation of the IRP will be developing an Analysis Plan which will determine the modeling approach for the IRP work. This Plan will address critical elements such as establishing the methodology for representing demand and supply side resources and their parameters in the optimization model, the approach for evaluating the economics of existing assets such as the combustion turbine and hydro fleet, developing an approach for consideration of essential grid services, developing metrics and screening criteria for the portfolios, and outlining the types of the modeling to be conducted (e.g. economic optimization vs iteration of reliability modeling).

3.2 Capacity Study (Attachment 17)

NS Power’s consultant, Energy and Environmental Economics Inc (E3), conducted statistical loss of load expectation (LOLE) studies[3] of the Nova Scotia system to establish the main assumptions to be used to define the capacity requirements in the IRP modeling: 1) the planning reserve margin (PRM), and 2) the capacity contribution of renewable resources, also known as Effective Load Carrying Capability (ELCC).

Key findings of this study include:

- The PRM required for the NS Power system to meet NPCC reliability standards can range from 17.8% to 21%.
- **Figure 4** below provides a summary of the calculated effective load carrying capability (ELCC), which represents capacity contribution, of existing renewable resources.
- As more variable renewable resources are introduced to the system, they will exhibit a declining marginal capacity value, as detailed in the study.

[3] LOLE calculates the average number of days per year an electricity system is expected to experience loss of load. A system with an LOLE less than or equal to 0.1 days/year is compliant with the 1-day-in-10-year NPCC requirement.

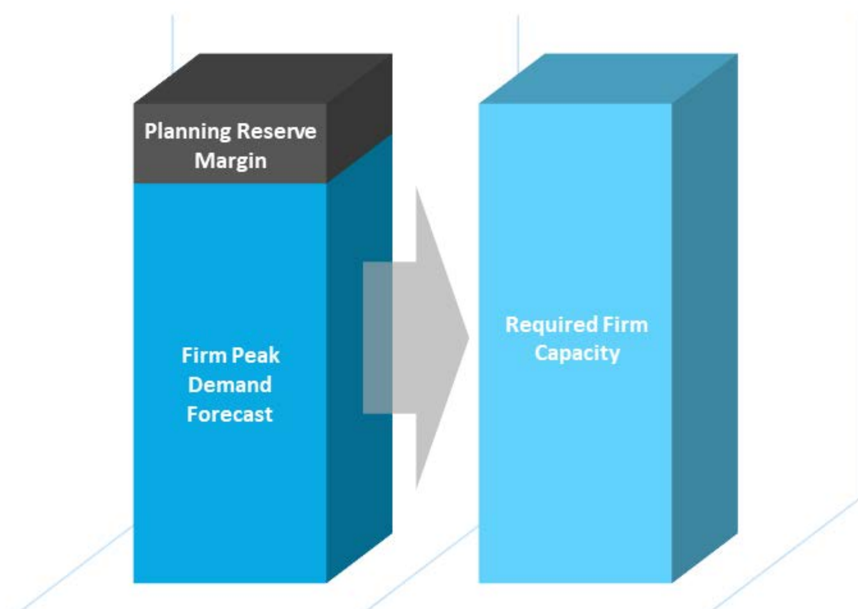
Figure 4: Calculated Capacity Value of Existing Resources

Resource	Installed Capacity (MW)	Average ELCC (%) {capacity value}	Energy Production (%) {capacity factor}
Wreck Cove	212	95.3%	17.7%
Wind	596	18.6%	35.2%
Tidal	19	12.3%	13.2%
Solar	1.7	4.4%	15.0%
Maritime Link Base Block	153	98.4%	66.7%

3.2.1 Planning Reserve Margin

The PRM is a key planning assumption as it directly impacts the minimum amount of firm capacity required to serve the system (which in turn determines how much firm capacity must be added or can be retired and/or how much firm demand needs to be removed or shifted). The PRM establishes the margin or "buffer" of capacity that is required above the forecast firm system peak in order to comply with Northeast Power Coordinating Council (NPCC) reliability criteria and avoid interruptions to firm service customers arising from unit outages, higher than anticipated system peaks or other system contingencies.

Figure 5: Illustration of the Planning Reserve Margin



NS Power has historically used a calculated PRM of 20% (i.e. designed a system with a minimum firm capacity equal to the forecasted firm peak load plus 20%). The results of the E3 study indicate the required PRM for the current resource mix in Nova Scotia ranges between 17.8% to 21%. NS Power will utilize this information to propose a PRM to use as the draft “base case” for the IRP modeling in the Assumptions Development phase.

It should be noted that a lower PRM (i.e. a lower minimum requirement for total firm capacity) does not necessarily translate into lower optimal system capacity and/or lower forecast system costs. NS Power has observed that in modeling exercises conducted to date, typically the optimization models economically retain more than the minimum capacity requirement. This is due to the other benefits that resources with firm capacity provide since optimization models take into account other factors such as access to economic energy, contribution to emissions reduction, and essential grid services (e.g. inertia, ramping, voltage support, frequency response, etc.).

These other benefits will often outweigh the economics of reducing the total installed capacity on the system. Therefore, the minimum amount of capacity is not necessarily the optimal amount of capacity. For example, in the Synapse modeling conducted as part of its Generation Utilization & Optimization study, all economically optimized portfolios had “excess” capacity (e.g. the model retained more capacity than the required minimum, exceeding the 20% planning reserve margin).

The PRM is dependent on the composition of a portfolio; changes in the resource mix can trigger changes in the PRM requirement. Accordingly, NS Power plans to incorporate a proposal for iterating on the PRM calculation in the Analysis Plan, particularly for portfolios with significant resource differences (e.g. high levels of renewables or major unit retirements), to provide insight on how the required PRM may change with different resource mixes. Through this iterative evaluation and the view of the upcoming likely resource mix, NS Power will be able to establish a PRM value and/or methodology to use for system design for the coming years at the conclusion of the IRP.

3.2.2 Capacity Value of Renewables

NS Power recognizes a key issue for consideration in the IRP will be evaluation of options for coal unit retirements. As discussed at the June 28 workshop, while there are potentially an increasing number of sources which can economically displace the energy produced by coal, the key challenge in Nova Scotia will be identifying cost-effective means to replace the firm capacity and essential grid services these units provide as generally the incremental operating and capital cost associated with maintaining these existing assets will be less than the capital required to build new firm capacity.

We face unique challenges in Nova Scotia in this regard, due to our limited interconnection to other provinces, absence of indigenous/extractable natural gas and the firm natural gas supply challenges this presents, and the nature of our winter peaking system (e.g. for many utilities solar can help to replace fossil fuel generation firm capacity, while in Nova Scotia, solar generation does not coincide with when customers need the most power at one time: winter evenings). Additionally, storage solutions paired with renewables have limitations due to the long duration requirements the storage would need to provide in order to ensure load would be served during the entire timeframe of the peak.

In order to ensure the peak demands of the system can be reliably met, it is important to quantify what contribution each resource can be expected to provide when required (i.e. the ELCC or capacity value). While conventional resources such as coal or natural gas units can normally be relied on at all times other than when they are offline for unexpected outages or planned maintenance periods, in contrast, intermittent renewable generation such as wind and solar only produce energy when the source is available (or in the case of storage, can only produce energy until its stores are depleted).

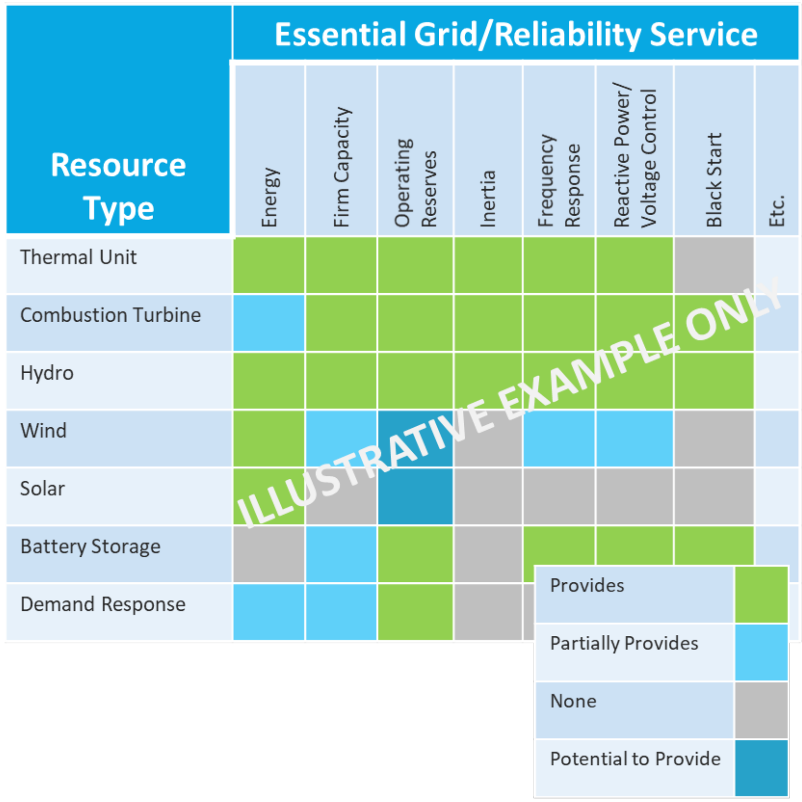
Calculating the ELCC of variable renewables allows the optimization model to consider the statistical likelihood the resource will be available to contribute when required. Essentially, this is calculating the "guaranteed capacity" that the grid can rely upon these resources to produce at any time, to ensure all firm customer load can be served. For this reason, simple historical averages of wind capacity factor (e.g. average energy production over the course of a year or during system peak hours) do not provide enough statistically significant data to represent the amount of capacity the grid will be counting on in order to be able to serve all firm customers during peak hours. The LOLE methodology is a broadly accepted statistical method for calculating the capacity value or ELCC of renewables. The results of these ELCC calculations are included in the Capacity Study (Attachment 17).

3.3 Supply Options Study (Attachment 18)

In the Supply Options Study, E3 has conducted jurisdictional reviews and provided recommendations on cost estimates to be used for new bulk grid supply option resources, as well as projections of the expected future changes to these resource costs. NS Power has also provided the projections of cost for its existing units, for consideration in the development of scenarios and assumptions to be used in the IRP Modeling phase.

A new consideration for this IRP will be determining the provision of essential grid services, particularly as the economics of energy from renewable resources improve. Essential grid services are required to maintain system balance and operate a stable grid. As noted above, we anticipate that while economic energy will likely be available in abundance, the main challenges for portfolio modeling will be ensuring the resource mix (and related cost) include adequate firm capacity and essential grid services which are required for reliability and grid stability, such as those shown in **Figure 6** below. NS Power will work with stakeholders to consider how the IRP can examine the provision of these services and will address this issue in the Analysis Plan Development Phase.

Figure 6: Illustrative Example of Essential Grid Services



3.3.1 New Bulk Grid Supply Options

NS Power has discussed the cost estimates for new utility scale supply options from E3's Supply Options Study with stakeholders and will use the feedback received to identify refinements to the "base case" and/or sensitivities to be modeled, all of which will be proposed in the Draft Assumptions Phase for review. The costs for other supply and demand side resources, such as import options and distributed energy resources, will also be developed as part of the Draft Assumptions Phase.

3.3.2 Sustaining Capital Investment for Existing Resources

While many of the sustaining capital investment forecast questions received from interested parties were quite detailed (these responses are provided in Appendix A), NS Power notes that in a complex, long term optimization, minor adjustments will be captured within the bookend "extreme" cases. In general, changes in the sustaining capital investment amount across the portfolio are not expected to have a major effect on the IRP results. For context, a 25% increase in sustaining capital costs for the thermal fleet would impact the annual revenue requirement calculated through the 2014 IRP by less than 1% (~0.7%).

Our focus for the IRP process will be to ensure we capture the bounds of all plausible outlooks on how much it may cost to retain the existing fleet, by establishing a reasonable “base case” for sustaining capital investment and exploring, in particular, a “high” sensitivity (as demonstrated in the example provided on page 81 of Attachment 18). The “base case” proposed in the Pre-IRP Deliverables is based on NS Power’s Asset Management methodology for forecasting sustaining capital investment according to the individual unit’s condition and its expected utilization (energy production, starts/cycles, and operating hours).

As discussed in Section 3.2, a key issue for consideration in this IRP will be evaluating potential coal unit retirements. While not critical to the overall revenue requirement calculations, the driving assumption for retirement decisions in the optimization model will be the annual sustaining capital required to retain the individual units. Accordingly, the “high” case for sustaining capital will be a critical sensitivity to test in the model, in order to provide insight into the relative importance of variations in sustaining capital as forecasts are adjusted year over year. NS Power will propose draft values for a “high” sensitivity case in the Assumptions Development phase and welcomes feedback on these assumptions.

3.4 Stability Study for Renewables Integration (Attachment 19)

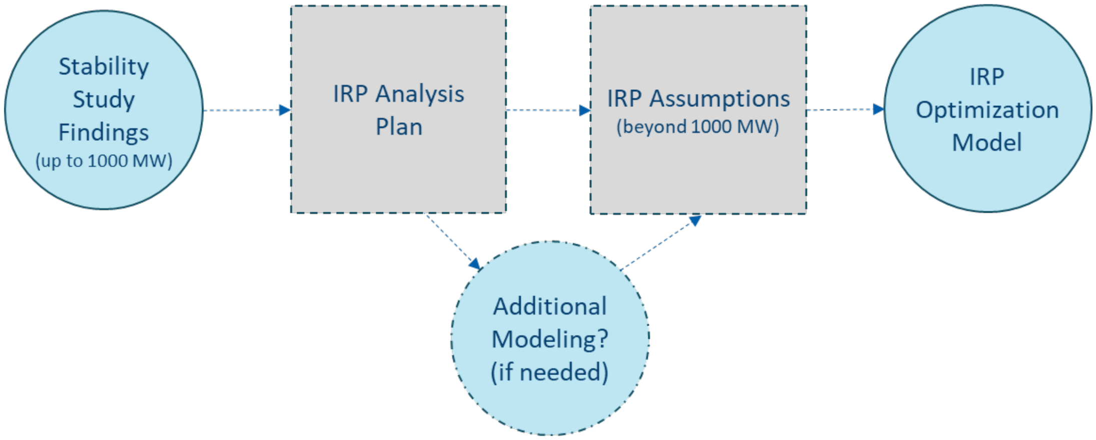
NS Power engaged a third-party expert, Power System Consultants (PSC), to conduct a technical transient system stability study to assess the specific requirements to increase the amount of renewable generation on the system from a long-term planning assumptions perspective. This type of study is a complex undertaking which focuses on understanding the issues that occur when the system is most critically stressed (e.g. during high or low load, during periods of high imports across interconnections, etc.). The purpose of the PSC Study was to confirm that the Nova Scotia system is stable at the current penetration level of wind, and to establish requirements for increased levels of wind/solar for use in the IRP modeling.

Key findings of this study include:

- Confirmation that the existing 600 MW of wind can be accommodated by the system as long as a minimum number of thermal generators remain online.
- Up to 1000 MW of wind/solar can be integrated with a 2nd tieline to NB and/or a battery and synchronous condenser solution. This represents the first major “next step” for renewables integration in Nova Scotia, and a significant finding for establishing the IRP assumptions.

NS Power expects that scenarios beyond 1000 MW of wind/solar will be tested in the IRP. As discussed in the August 27 workshop, the Analysis Plan will propose a methodology for estimating the integration costs of additional wind/solar on the system, based on the findings of the Stability Study, as illustrated in **Figure 7** below. These integration costs will then be included in the Draft Assumptions for stakeholder consideration and feedback.

Figure 7: Process for Establishing Wind & Solar Interconnection Cost Assumptions



Many of the questions posed regarding the Stability Study for Renewables Integration refer to economic issues such as consideration of dispatchable wind, contracts, and "backing up" renewable energy. These types of issues are not considered in transient system stability studies, which look at on the physical state of the grid for a very short period of time following a system disturbance. For example, in a transient stability study, a parameter of importance would be the load level on a particular interconnection; it would not matter which contracts were in place to provide that load. The economic considerations and contractual elements raised by interested parties will be addressed by both the development of Draft Assumptions and the IRP Modeling Phase (many of these issues are inherently part of the IRP model optimization).

3.5 Demand Response Assumptions (Attachment 20)

NS Power provided proposed assumptions for three specific Demand Response (DR) programs: water heater controls, electric vehicle peak shifting, and a residential battery program. Efficiency One (E1) has developed information on DR programs as part of its DSM Potential Study; the E1 and NS Power teams have been working together to review the DR programs and will continue to collaborate in order to refine the DR Programs to be proposed in the Assumptions Development Phase.

4. Conclusion

The global drive for carbon reduction and the potential to achieve this through electrification of fossil fuel-based sectors (i.e. heating and transportation) means that the 2020 IRP will be the most important resource planning exercise undertaken by NS Power to date. Through experience gained from prior IRP exercises and with the assistance of experts engaged in the current process and through continued collaboration with stakeholders, the Company is confident we have the tools to execute this undertaking in a manner which is consistent with industry-leading IRP practices that will deliver a robust and cost-effective long-term electricity plan for Nova Scotia.

To complete this work effectively and efficiently, it will be important to establish clearly in the Terms of Reference areas that are in-scope and strategic, with the potential to drive a material change in modelling outcomes and those that are more "tactical" in nature and best addressed through model sensitivities and/or continued reliance on the established regulatory processes (e.g. sustaining capital levels, generation asset ownership). The Company presents this pre-IRP work with the objective that it will inform the IRP Terms of Reference development and streamline future work to enable parties to meet the Board's timelines and produce results which are clearly communicated, well-understood and supported broadly by IRP process participants. As described in the sections above, NSP is confident that the feedback received from stakeholders on the Pre-IRP Deliverables can be incorporated in the broader IRP process, specifically in the Analysis Plan, Assumptions Development, and Portfolio Modeling phases.

The Company thanks all IRP participants for their feedback to date. We look forward to working with all parties and are excited by the opportunity to develop a shared vision for the future of the electricity sector in our Province.

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October 5, 2018

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Judith Ferguson
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Dear Ms. Ferguson:

Integrated Resource Planning (IRP) and M08059 -- Generation Utilization and Optimization

The Board has concluded its review of the Synapse Energy Economics, Inc. (Synapse) final report dated May 1, 2018 in matter M08059, along with submissions and replies filed by participants in that matter. The Board panel considering this matter included Peter W. Gurnham, Q.C., Chair, Roland A. Deveau, Q.C., Vice Chair, and Steven M. Murphy, MBA, P.Eng., Member.

There is a clear indication that an Integrated Resource Planning (IRP) analysis needs to be undertaken, and this is further supported by numerous comments made by Bates White in their recent fuel audit report.

In its comments of June 7, 2018 on the Synapse final report, NS Power expressed its support for all nine recommendations included in the Synapse final report, and stated:

> As noted below, NS Power does not believe that additional process with respect to the Synapse Report is necessary at this time.
>
> …
>
> The "planning window" this analysis creates, combined with clarity being achieved on carbon policy, will provide NS Power and stakeholders with an important opportunity over the next year to focus on the development of complete and accurate resource planning assumptions necessary to support the next IRP.

In its reply submission of July 9, 2018 to stakeholder comments on the Synapse final report, Synapse stated:

> NS Power highlights, appropriately, one of our core findings that under "reference" load levels and other reference scenario parameters (wind capacity credit, new wind installation limits, no 2nd 345 kV tie, sustaining capital amounts) retention of the thermal fleet is indicated through 2030.[1] And, NS Power also notes, properly, that these results do not reflect a "final determination as to the long-term utilization of these generation units".
>
> However, the entirety of our analysis indicates that almost all scenarios *other than* the reference scenario exhibit lower overall planning period costs,[2] and a number of those scenarios indicate economic retirement of a second coal unit (i.e., besides Lingan 2) earlier than 2030. The three lowest cost scenarios – noted on page 2 of our report (scenarios 8, 14, and 17) – show a second coal unit retirement between 2024-2027, indicating the economic importance of carefully considering the pattern of near-term capital investment for what will be the next coal unit retirement after Lingan 2…In total, these results show that retention of the entire thermal fleet through 2030 is economic only under the reference plan assumptions, and the scenario analyses show that those assumptions generally do not represent the lowest-cost planning path. Most importantly, the results show that NS Power should focus on identifying the best candidate for retirement after Lingan 2.

The Synapse final report on generation utilization and optimization identified the following nine recommendations which need to be undertaken as the first phase of an IRP process, in order to ensure the completeness and accuracy of input assumptions used in the analysis:

1. Confirm costs and achievable potential for incremental energy efficiency. As seen, energy efficiency displaces higher cost energy sources in the province (gas, oil, imports) and the IRP must fully reflect this resource option. [Note that EfficiencyOne has been directed to file a DSM Potential Study by July 31, 2019.]

2. Determine costs and achievable potential for peak-load reducing demand response. Construct specific cost and quantity curves to allow for either resource selection (in Plexos) based on specific demand side resources, or scenario analysis utilizing alternative peak load and annual energy projections.

3. Monitor and comprehensively investigate costs for bulk-scale battery storage of different durations. The Plexos results indicate economic battery builds in different scenarios and reflect the importance of this resource to serve as peaking capacity.

4. Monitor, track and project sustaining capital costs for the thermal fleet. Sustaining capital costs incurred a range of 6.5% to 10.4% of total NPVRR costs in our main scenarios. It is critical to continue to assess the pattern of these costs and project future costs.

5. Establish requirements to allow increased levels of wind on NSPI system. Two threshold criteria to allow increased levels of cost-effective wind resources are completion of a second 345 kV intertie to New Brunswick, and assessment of NSPI's Provincial transmission system and related support services (to maintain stability and voltage criteria). NSPI should determine, with specificity, the set of technical improvements required to allow different increments of additional wind on their system. This should include the effect of additional transmission capacity to New Brunswick, the presence of the Maritime Link, and the ability to further increase wind penetration through transmission grid reinforcement. This should also recognize that the introduction of bulk scale battery storage as a possible capacity resource that can provide co-benefits associated with stability and voltage support.

6. Continue joint dispatch efforts and investigate increased planning, unit commitment and reserve sharing opportunities with New Brunswick, Newfoundland and Prince Edward Island. Increased

coordination among the Maritime Provinces is likely required to maintain reliability with increased wind resource utilization.

7. Determine the capacity and unit commitment requirements needed in association with the Tufts Cove thermal units, to allow appropriate parameterization in Plexos to enable possible economic retirement.

8. Identify candidates for the "next" coal retirement alternative after Lingan 2. Consider "rank ordering" the units to establish a priority order reflecting best-to-worst economic performers across the thermal fleet. While projecting sustainable capital needs is an uncertain exercise, the potential to avoid significant major expenses at different points in time over the next decade illustrates the importance of establishing such a ranking.

9. Monitor natural gas price and availability trends in the Maritimes.

In addition, the following items noted in the Bates White fuel audit report likely should be addressed during the first phase of the IRP process:

- Continue to evaluate new and existing wind resources in order to establish an appropriate firm capacity value for each installation.
- The 2013 CT Asset Optimization Study does not fully inform the decision to invest in the preservation of these units vis-à-vis replacing them with more modern CTs or another type of fast ramping generation unit. NSPI should compare the economics of replacing them with newer CTs or another type of fast ramping generation.
- Determine the extent of any capital investment that may be required at Trenton 6 or the Point Tupper Marine Terminal after the current supply of domestic coal is no longer available at the end of 2019.
- Complete a detailed analysis to determine the lowest planning reserve margin necessary to meet NPCC requirements, rather then just assessing if 20% remains in compliance. Considering that NERC's current North American references range between 10.6% and 23.7%, perhaps the analysis should assess reliability and economics for a range of planning reserve margins.

The Board directs NS Power to undertake an IRP process for completion by mid-2020. Considering that the DSM Potential Study is to be filed by July 31, 2019, NS Power should aim to complete all of the above pre-IRP analyses by that same date. This will enable proceeding with timely confirmation of appropriate input assumptions for use in the modeling and analysis phase of the IRP process.

Also, recognizing that the DSM Potential Study is a critical component in the IRP analysis, EfficiencyOne is directed to engage NS Power and stakeholders throughout the development of the DSM Potential Study in order to minimize any concerns prior to filing the final report.

Board Counsel and Board staff have met with NS Power to discuss the anticipated IRP process and associated timeline. The Board will also be engaging the services of Synapse as active participants in all aspects of the IRP process. In addition, as in the past, stakeholders will be provided with an opportunity to participate in this process.

Having regard to the foregoing, the generation utilization and optimization matter is considered concluded.

Yours truly,

Crystal Henwood

for Doreen Friis
Regulatory Affairs Officer/Clerk

c: S. Bruce Outhouse, Q.C., Board Counsel
Nicole Godbout, NS Power
Brian Curry, NS Power
Gina Thompson, EfficiencyOne
Bob Fagan, Synapse
Vincent Musco, Bates White
Peter Craig, NSDOE
M08059 Participants

Nova Scotia POWER An Emera Company

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

May 17, 2019

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: NS Power 2020 Integrated Resource Plan (IRP) – Pre-IRP Workshops

In its letter dated October 5, 2018, the Board directed NS Power to undertake an IRP process for completion by mid-2020, and to aim to complete the pre-IRP analyses (recommended by the Generation Utilization and Optimization Synapse report and the Bates White report dated July 24, 2018 from its audit of the Fuel Adjustment Mechanism for 2016-2017) by July 31, 2019.

NS Power's pre-IRP deliverables as set out in the Board's letter include the following:

1. Completing loss of load expectation (LOLE) study to establish planning reserve margin, capacity value of wind, and battery storage duration requirements [related to Bates White items].

2. Developing resource options assumptions for new supply-side options (including initial investment capital, ongoing operating costs, sustaining capital, performance capabilities, etc.) [related to Synapse recommendation #3 and Bates White items] and develop cost and performance projections for existing fleet [related to Synapse recommendation #4, 7, 8 and Bates White items].

3. Developing assumptions for demand response resources [related to Synapse recommendation #2] including estimated program cost and peak load impact.

4. Conducting study of transmission requirements for increased levels of renewables on the Nova Scotia system [related to Synapse recommendation #5, 6]

The Company also anticipates that Synapse recommendation 1 will be addressed by E1's Potential Study (Synapse recommendations 6, 8, and 9 will be addressed in the broader IRP analysis process (e.g. during assumptions development or in the modeling phase itself).

NS Power has been providing Board staff with regular updates on these items and confirms the Company is on-track to have them completed by July 31, 2019.

The Company would like to begin engaging with interested parties prior to this date, and is planning a series of workshops to discuss the IRP process, key issues, and the status of its pre-IRP deliverables. Specifically, NS Power will be holding an initial Webex conference on Friday, May 24, 2019 at 10:00am where the Company would provide an overview of the pre-IRP deliverables as well as an outline of the intended pre-IRP workshops with interested parties. The Company is currently anticipating two pre-IRP additional workshops (one June and one in July) to provide interested parties with background IRP information, discuss key issues and changes in the planning environment, and present updates on the draft deliverables for discussion.

NS Power respectfully requests that the Board circulate this update to the appropriate distribution lists with the request that recipients confirm their interest in participating in the Company's pre-IRP workshops, to Regulatory.Affairs@nspower.ca, in order to better enable the Company to move forward with this engagement process.

Yours truly,

Nicole Godbout
Director, Regulatory

c. Judith Ferguson
Mark Sidebottom
Lia MacDonald

Nova Scotia POWER An Emera Company

MAY 24, 2019

2019-2020 Integrated Resource Plan: Stakeholder Session #1

Today's Agenda

1. Overview of the IRP Regulatory Process

2. NSP Pre-IRP Deliverables for July 31
   a) Capacity Study
   b) Bulk Grid Supply Options Study
   c) Demand Response Assumptions
   d) Renewables Stability Study

3. Plan for June & July Stakeholder Engagement Sessions

Overview of the IRP Regulatory Process

now → **Pre-IRP** Deliverables → JUL 31

- Capacity Study
- Supply Options Study
- DR Assumptions
- Renewables Stability Study

JUL 31 → **Core IRP Process** resulting in Final Report → mid 2020

- Terms of Reference
- Analysis Plan
- Scenario Development
- Assumptions
- Modeling
- Conclusion
- Report

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An Emera Company

NS Power's IRP Consultants

NS Power has engaged E3 (Energy Environmental Economics) to assist with completion of some of its pre-IRP analysis and to help guide the utility through the IRP process.

» E3 is a San Francisco-based consultancy specializing in electricity economics

» E3 consults extensively for utilities, developers, government agencies and environmental groups on clean energy issues:

- United Nations Deep Decarbonization Pathways Project
- Planning for California's climate and renewable energy goals
- 100% renewables studies for California, Hawaii, and New York

NS Power has also engaged PSC (Power Systems Consultants) to complete the Transmission Planning work assessing increased renewables requirements.

» PSC is a global firm providing specialized consulting exclusively to the electrical power industry

» PSC has extensive expertise in generator, load and transmission interconnection studies in the US, Canada, Australia, New Zealand, the UK, and Ireland.

NSP Pre-IRP Deliverables

1. Capacity Study

DESCRIPTION:
Consultant LOLE study which calculates the required Planning Reserve Margin, wind capacity value, and requirements for storage durations for capacity for the NSP system.

DELIVERABLE TYPE: Report

STATUS: ON TRACK

2. Supply Options Study

DESCRIPTION:
Consultant study which estimates the initial and sustaining costs and performance of new bulk grid supply options and future trends. NSP study of expected sustaining capital and performance of existing assets.

DELIVERABLE TYPE: Report

STATUS: ON TRACK

Nova Scotia POWER An Emera Company

NSP Pre-IRP Deliverables

3. Demand Response Assumptions

DESCRIPTION:
Draft modeling assumptions (cost and load impacts) for 1 to 3 specific DR programs.

DELIVERABLE TYPE: Assumptions Deck

STATUS: ON TRACK

4. Renewables Stability Study

DESCRIPTION:
Consultant report identifying transmission requirements and system design considerations for increased levels of renewables on the NSP grid based on technical system studies.

DELIVERABLE TYPE: Report

STATUS: ON TRACK

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NSP Pre-IRP Deliverables

Party	Recommendation	Expected Delivery
Synapse	1. Confirm costs and achievable potential for incremental energy efficiency.	E1 Potential Study
	2. Determine costs and achievable potential for peak-load reducing demand response. Construct specific cost and quantity curves to allow for either resource selection (in Plexos) based on specific demand side resources, or scenario analysis utilizing alternative peak load and annual energy projections.	DR Assumptions and/or E1 Potential Study
	3. Monitor and comprehensively investigate costs for bulk-scale battery storage of different durations.	Supply Options Study & Capacity Study
	4. Monitor, track and project sustaining capital costs for the thermal fleet.	Supply Options Study
	5. Establish requirements to allow increased levels of wind on NSPI system. … NSPI should determine, with specificity, the set of technical improvements required to allow different increments of additional wind on their system.	Renewables Stability Study
	6. Continue joint dispatch efforts and investigate increased planning, unit commitment and reserve sharing opportunities with New Brunswick, Newfoundland and Prince Edward Island.	Operations & Regional Studies
	7. Determine the capacity and unit commitment requirements needed in association with the Tufts Cove thermal units, to allow appropriate parameterization in Plexos to enable possible economic retirement.	Supply Options Study & IRP Assumptions
	8. Identify candidates for the "next" coal retirement alternative after Lingan 2.	Supply Options Study & IRP Modeling
	9. Monitor natural gas price and availability trends in the Maritimes.	IRP Assumptions

Nova Scotia POWER
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NSP Pre-IRP Deliverables

Party	Recommendation	Expected Delivery
Bates White	Continue to evaluate new and existing wind resources in order to establish an appropriate firm capacity value for each installation.	Capacity Study
	The 2013 CT Asset Optimization Study does not fully inform the decision to invest in the preservation of these units vis-a-vis replacing them with more modern CTs or another type of fast ramping generation unit. NSPI should compare the economics of replacing them with newer CTs or another type of fast ramping generation.	Supply Options Study & IRP Modeling
	Determine the extent of any capital investment that may be required at Trenton 6 or the Point Tupper Marine Terminal after the current supply of domestic coal is no longer available at the end of 2019.	Supply Options Study
	Complete a detailed analysis to determine the lowest planning reserve margin necessary to meet NPCC requirements, rather then just assessing if 20% remains in compliance. Considering that NERC's current North American references range between 10.6% and 23.7%, perhaps the analysis should assess reliability and economics for a range of planning reserve margins.	Capacity Study

Proposed Pre-IRP Stakeholder Sessions

Session 1 (Today)	Session 2	Session 3
- IRP regulatory process overview - Pre-IRP deliverables update - Review of stakeholder sessions plan	- Overview of IRP exercise - NS Power System 101 - Uncertainties in the Planning Environment - Industry & Customer Trends to Consider - Pre-IRP Deliverables Status Update	- Review Draft Supply Options Study - Review Draft Capacity Study - Update on remaining pre-IRP Deliverables
May 24, 2019	**Late June (TBD)**	**Late July (TBD)**
~1 hour	~3 hours	~3 hours

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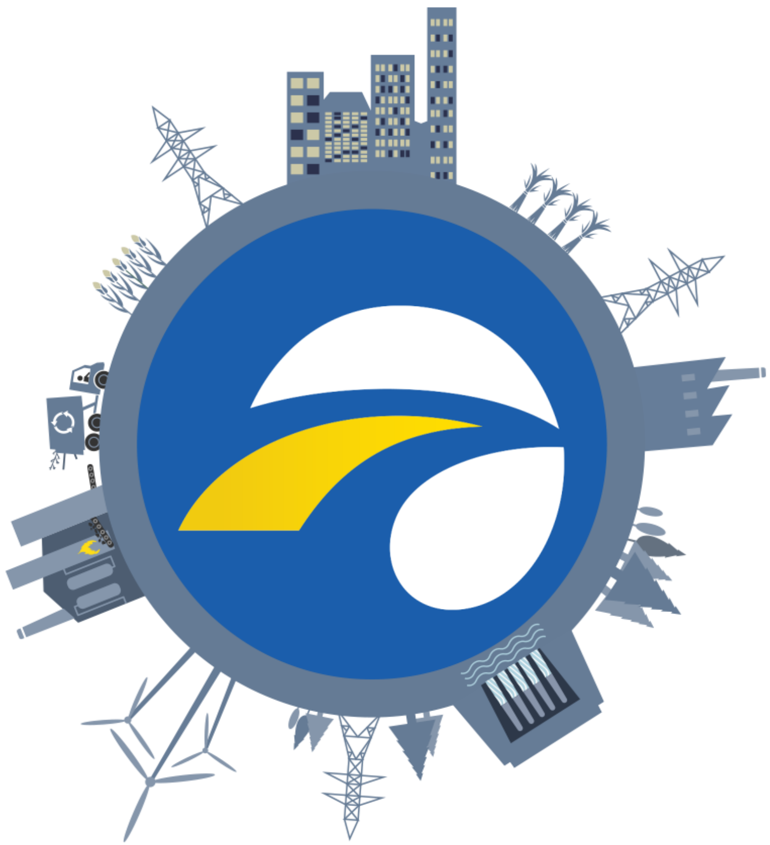
Questions/Discussion



Energy+Environmental Economics

Industry Trends: IRP 101

Nova Scotia Power

Stakeholder Session #2

June 28, 2019

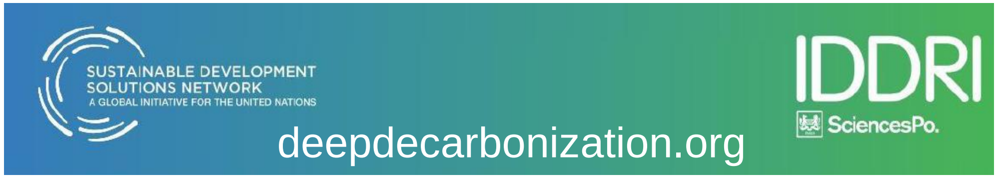
Zach Ming, Sr. Managing Consultant
Arne Olson, Sr. Partner

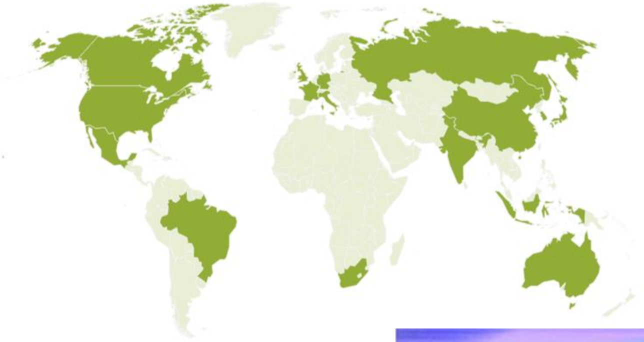
Outline

- IRP Overview
- E3 Introduction
- Electricity Industry Trends in Long-Term Planning
  - Challenges in Other Jurisdictions
- Nova Scotia Power System Overview
  - Challenges in Nova Scotia

About E3

- E3 is a San Francisco-based consulting firm founded in 1989 specializing in electricity economics with approximately 60 staff
- E3 consults extensively for utilities, developers, government agencies, and environmental groups on clean energy issues
- Services for a wide variety of clients made possible through an analytical, unbiased approach
- Our experts provide critical thought leadership, publishing regularly in peer reviewed journals and leading industry publications





Overview of E3 Practice Areas

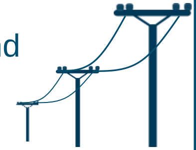
- **E3 focuses on all segments of the electricity sector and their interconnectedness with the rest of the energy economy in order to provide holistic analysis and recommendations for our clients**

E3 has five defined working groups that create continual innovation from cutting edge projects and constant cross-fertilization of best practices across the groups

DERs & Rates

Analyzes distributed energy resources, emphasizing their costs and benefits now and in the future

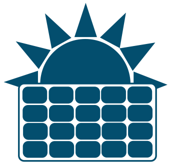
Supports rate design and distribution system planning



Clean Energy

Provides market and policy analysis on clean energy technologies and climate change issues

Includes comprehensive and long-term GHG analysis



Asset Valuation

Determines asset values from multiple perspectives

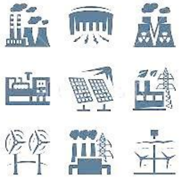
Uses proprietary in-house models and in-depth knowledge of public policy, regulation and market institutions

$

Planning

Develops and deploys proprietary tools to aid resource planners

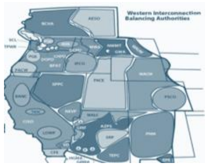
Informs longer-term system planning and forecasting



Market Analysis

Models wholesale energy markets both in isolation and as part of broader, more regional markets

Key insights to inform system operators and market participants



E3 Experience in Resource Planning

+ **E3 has worked with a wide range of clients that are increasingly writing the script for the emerging clean energy transition to understand how to plan deeply decarbonized electricity systems**
  - **California PUC:** Assisting the CPUC in administration of IRP program mandated by SB 350 by developing a 'Reference System Plan' that achieves 40% GHG emission reductions by 2030 using the RESOLVE model
  - **Pacific Northwest Low Carbon Scenarios Study:** Retained to investigate the economics of Swan Lake and Goldendale "closed-loop" pumped storage hydro projects (1,600 MW total) in Oregon and Washington
  - **Sacramento Municipal Utilities District:** Assisting with 2018 IRP to evaluate long-term clean energy goals including GHG emission reductions of 90-100% by 2040
  - **Los Angeles Department of Water and Power (LADWP):** Evaluated reliability contributions of clean energy alternatives to natural gas once-through-cooling plant repowerings
  - **Hawaiian Electric Company (HECO):** Developed an affordable, technical feasible Power Supply Improvement Plan (PSIP) consistent with Hawaii's goal of 100 percent renewable energy by 2045
  - **Xcel Energy Upper Midwest IRP:** Provided support to Xcel Minnesota by conducting independent technical analysis to examine how to meet long-term carbon reduction goals along with associated costs as part of their 2019 IRP process

+ **Through these projects, E3 has developed an unparalleled understanding of the role of storage within highly and deeply decarbonized renewable electricity systems**

Key E3 Staff Bios

Arne Olson
Senior Partner

Mr. Olson leads E3's resource planning practice. Since joining E3 in 2002, he has led numerous analyses of how renewable energy and greenhouse gas policy goals could impact system operations, transmission, and energy markets.

M.S. in international energy management and policy from the University of Pennsylvania and the Institut Francais du Petrole and a B.S. in statistics and mathematical sciences from the University of Washington

Zach Ming
Senior Managing Consultant

Mr. Ming leads the development of energy models and communicates findings on behalf of utilities, regulatory agencies, and trade groups. Since joining E3 in 2013, he has managed numerous resource planning projects and teaches a class at Stanford University on electricity economics.

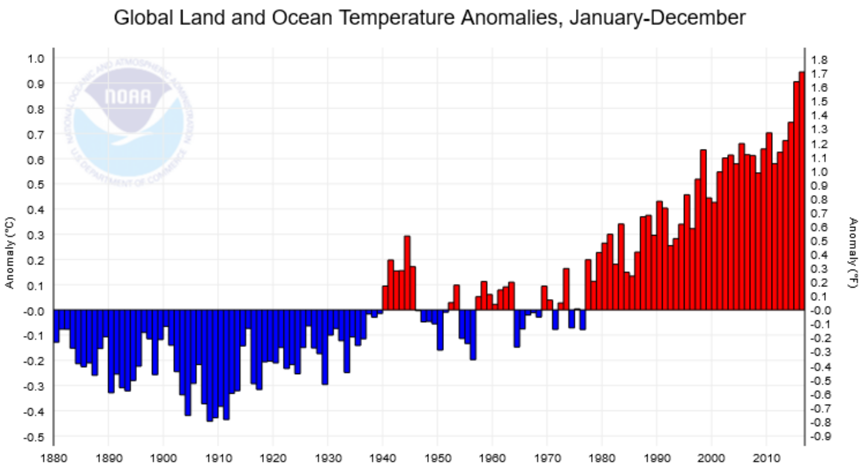
M.S. in management science and engineering and a B.S. in civil and environmental engineering from Stanford University.

Energy+Environmental Economics

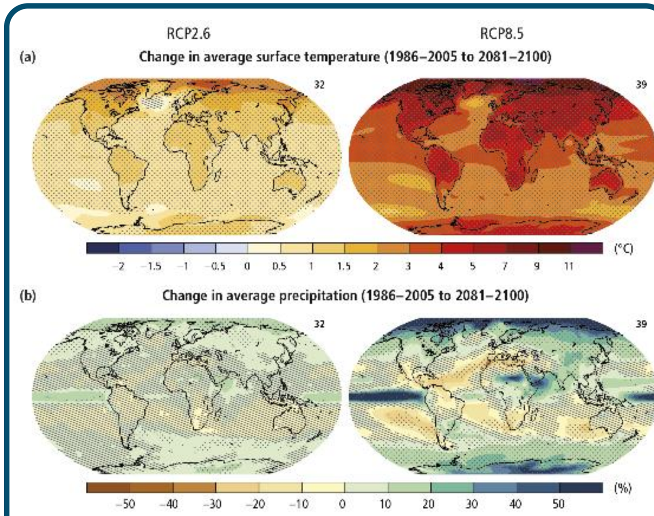
Trends in the Electricity Industry

Decarbonization

- **The 2016 Paris agreement committed industrialized nations to 80% reductions below 1990 levels by 2050**
    - Roughly consistent with IPCC/UNFCC goal of keeping global average temperature rise within 2°C to avert catastrophic climate change
- **If current trends continue, 2°C aggregate warming will be exceeded**



Source: NOAA, https://www.ncdc.noaa.gov/monitoring-references/faq/indicators.php Global annual average temperature measured over land and oceans. Red bars indicate temperatures above and blue bars indicate temperatures below the 1901-2000 average temperature.



Source: IPCC Global Assessment Report 5, SPM.07

Declining Prices of Renewables and Energy Storage

Levelized Wind PPA Prices by PPA Execution Date

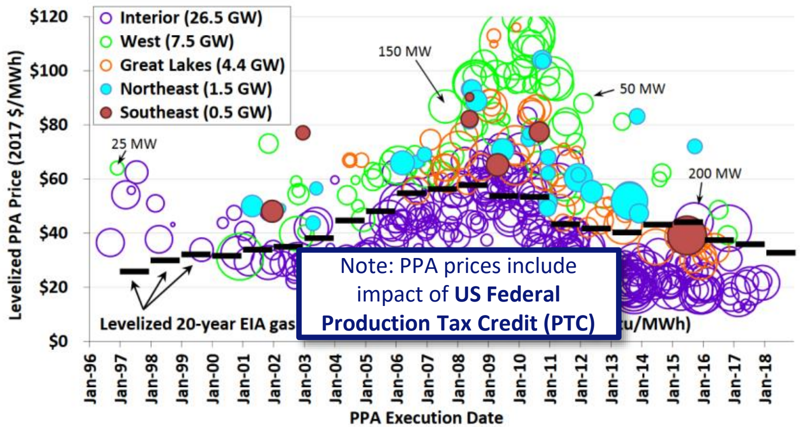


Figure source: 2017 Wind Technologies Market Report (LBNL)

+ **Declining prices of clean energy technologies such as wind, solar, and energy storage is leading to aggressive renewable energy policies and targets as well as adoption on the basis of economics alone in many jurisdictions**

NREL Utility-Scale PV System Cost Benchmark Summary (Inflation Adjusted), 2010-2018

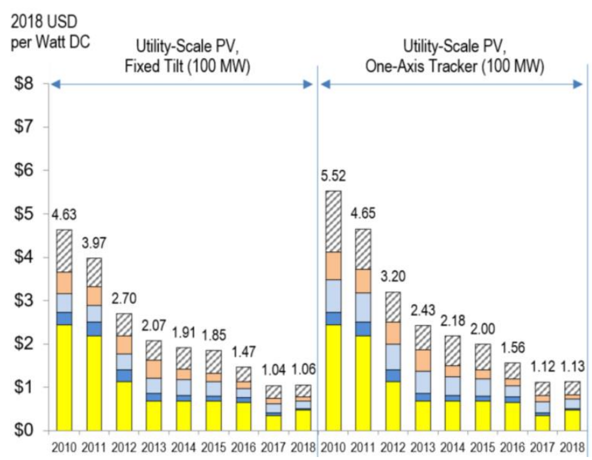


Figure source: US Solar Photovoltaic Cost Benchmark: Q1 2018 (NREL)

Lithium-Ion Battery Price, Historical and Forecast, 2010-2030

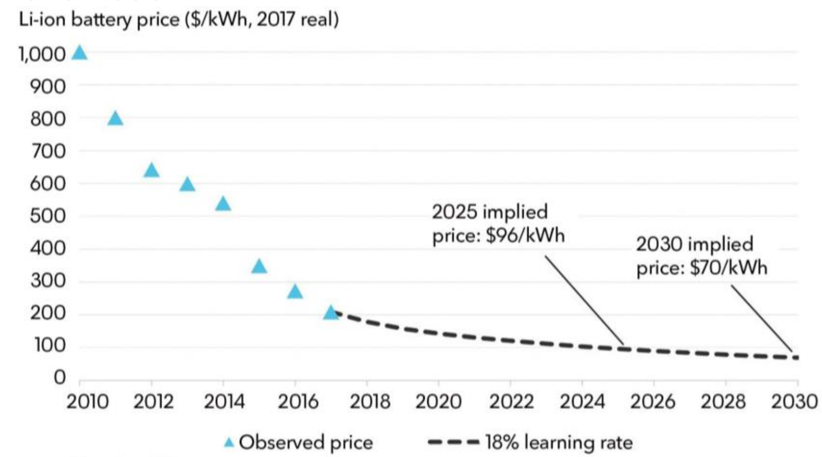
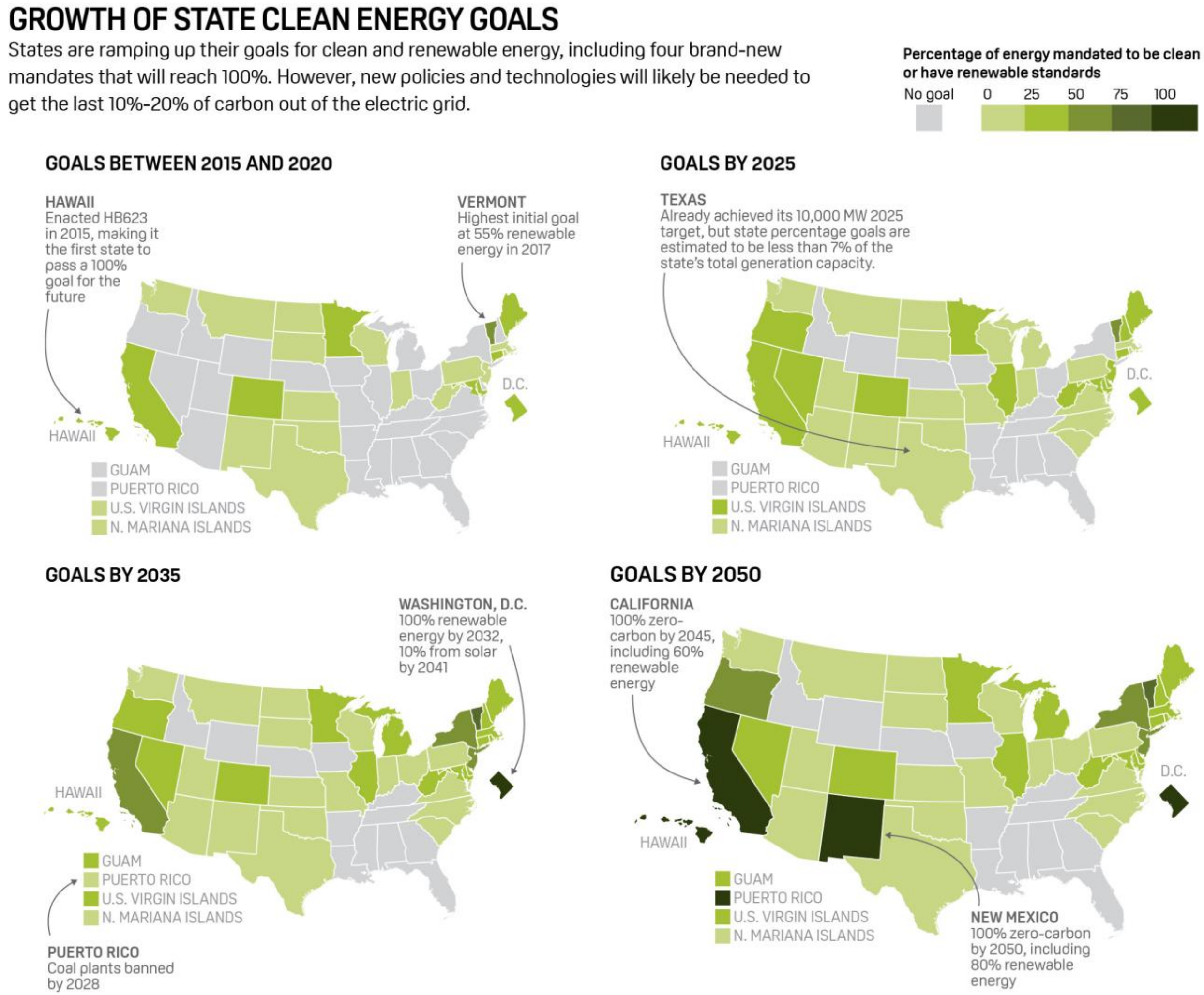


Figure source: Bloomberg NEF

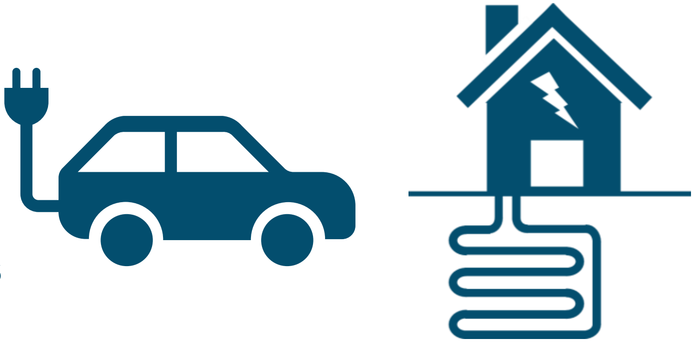
High-Volume Renewable Targets

- **Many states are pushing beyond existing RPS policies and goals into “high-volume” targets of 50%-100%**
- **100% clean electricity targets**
  - California
  - New Mexico
  - Washington
  - Xcel Energy
  - Idaho Power
  - Many municipalities
  - *…New York*
  - *…Illinois*



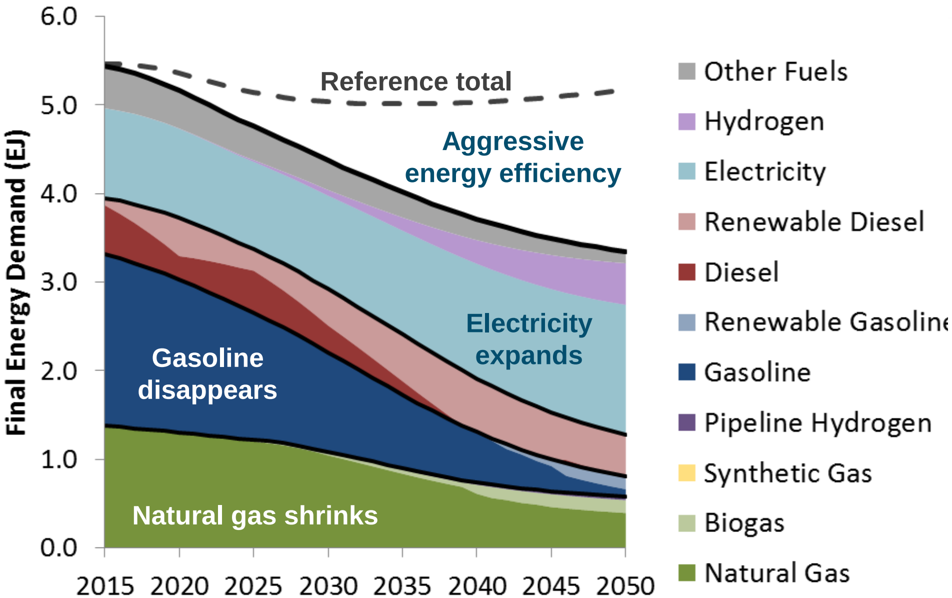
Electrification

- A growing consensus of economy-wide decarbonization studies show the important role that electrification of vehicles and buildings will play in a least-cost plan
- In many jurisdictions, total electricity demand is expected to grow in the long-run despite investments in energy efficiency



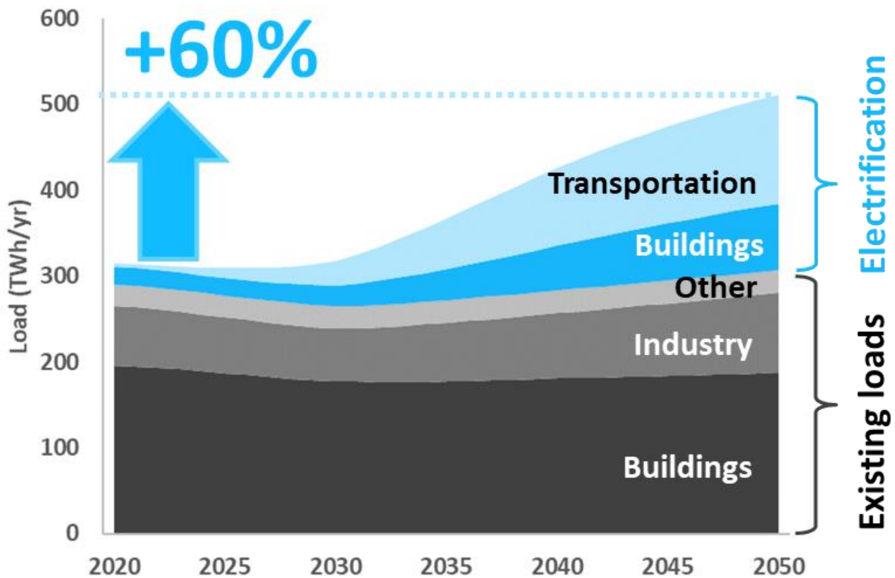
Final Energy Demand by Major Fuel Type

80% GHG Reduction Case in California



Final Electricity Demand

80% GHG Reduction Case in California



Source: E3 PATHWAYS

Distributed Energy Resources

- **DERs are technologies located close to customer load or on the customer side of the electricity meter i.e. behind-the-meter**

Energy Efficiency | **Solar PV** | **Battery Storage** | **Smart Thermostats** | **Electric Vehicles** | **… and more**

72°

- **DERs have gained popularity in recent years buoyed by technological advances (sensors, monitors, communication), price declines (solar PV, battery storage), and changing customer preferences (cleaner, cheaper, independent)**
- **DERs that are responsive to the needs of the grid through flexibility and communication have the potential to play a key role in the integration of renewable energy for decarbonization**
  - Smart thermostats that pre-heat or pre-cool a home
  - Electric vehicles and water heaters that charge when it's sunny or windy
  - Appliances such as dishwashers that delay operation until system demand is lower

TESLA

IceEnergy

Retail Rate Structures

+ **Reforms to existing retail rate structures will be necessary to enable both <u>electrification</u> and <u>renewable energy</u> in the future**

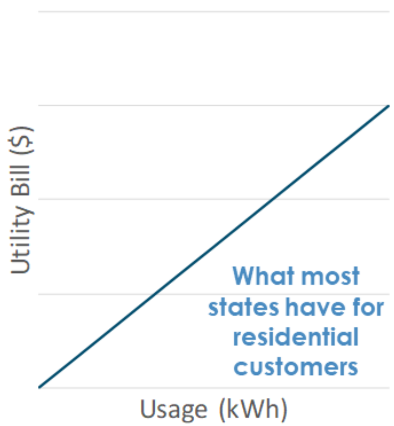
Volumetric

Pros

Simple, relatively fair when customers are homogenous, good incentives for efficiency and solar

Cons

Poorly aligned with utility costs, cannot incentivize flexible loads, can create cost-shifts and cross-subsidies



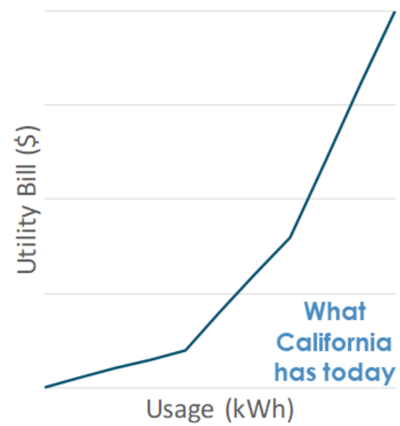
Tiered

Pros

Really good at incentivizing efficiency and solar, progressive (larger, wealthier customers pay more)

Cons

Extremely poorly aligned with utility costs, cannot incentivize flexible loads, can create cost-shifts and cross-subsidies



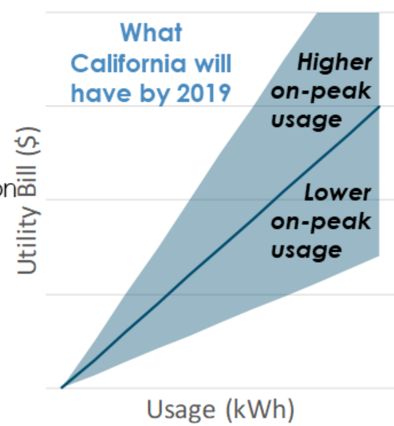
Time Differentiated

Pros

Better aligned with utility costs, can incentivize flexible loads, fair allocation of costs to customers

Cons

Complex, can remove existing incentives for efficiency and solar



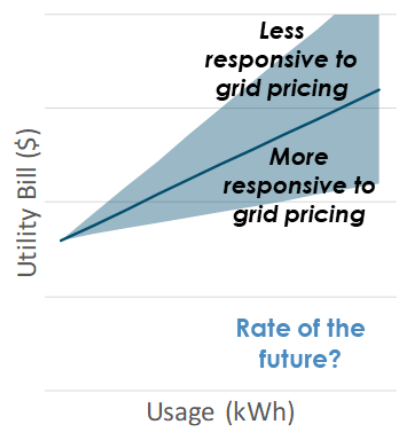
Fixed/Demand Charge & Real Time Pricing

Pros

Most economically efficient, fair allocation of costs to customers, best at incentivizing flexible loads

Cons

Complicated, poor incentive for efficiency and solar

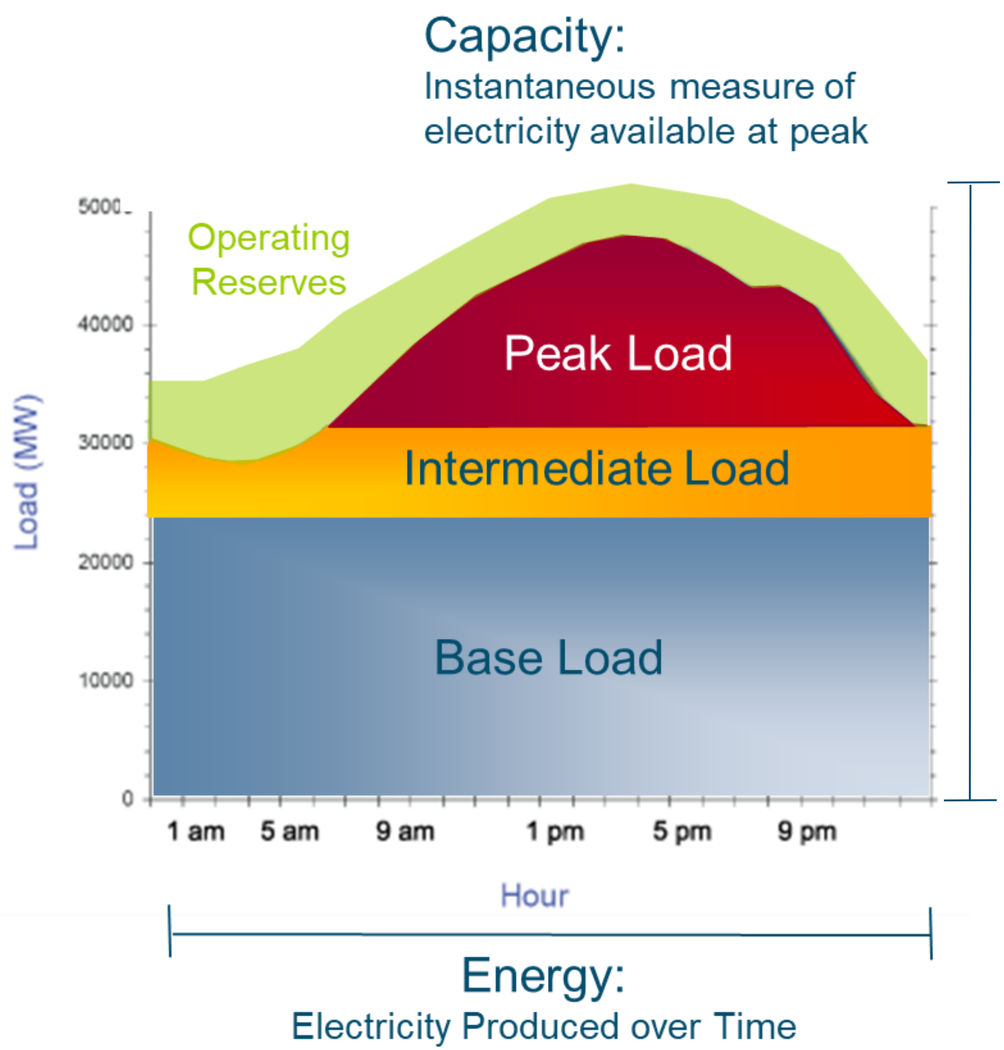


Energy+Environmental Economics

IRP 101

Basic Anatomy of a Resource Plan

- **Energy Needs: portfolio of resources dispatched to meet utility annual load in each year (comprising owned resources, contracts, and market purchases)**
  - Reflects expected operations of plans based on operational characteristics as well as utility interactions with wholesale markets
- **Capacity Needs: portfolio of resources available to meet peak demand (plus a planning reserve margin) in each year**
  - Planning reserve margin in Nova Scotia is 20% above peak load
    - -15° C on January weekday evening



Source: NERC

Emergence of Integrated Resource Planning

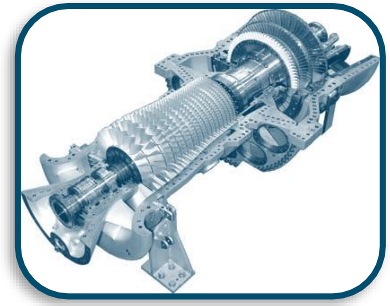
- The concept of integrated resource planning "IRP" emerged in the 1980's, bringing a new suite of demand-side resources to the table as options in planning
- Today, some – but not all – utility IRPs consider supply and demand-side resources on a level playing field
  - More often, demand-side resources are evaluated in a separate step and integrated into the planning process as assumptions

The Traditional Planning Paradigm

+ **Historically, utility planners have built electricity resource portfolios with 3 types of resources by weighing fixed and variable cost**

Baseload
coal, nuclear

Intermediate
combined cycle gas



Peaker
combustion turbine gas

Increasing **variable** costs →

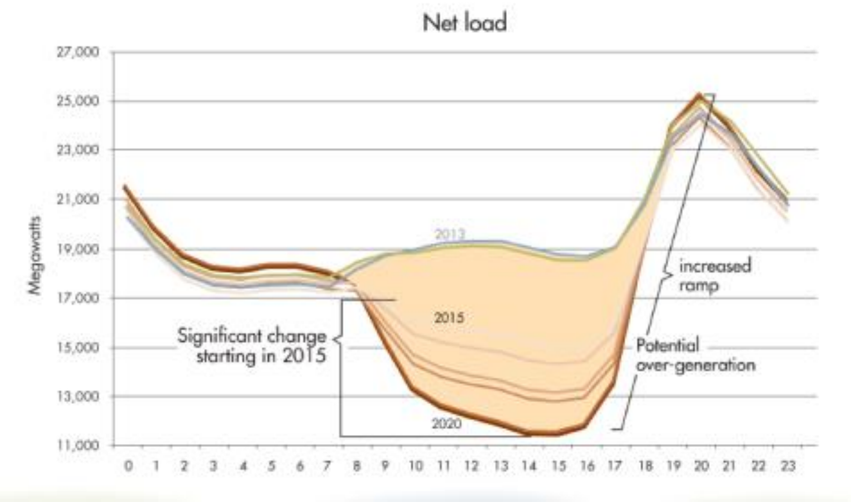
← Increasing **fixed** costs

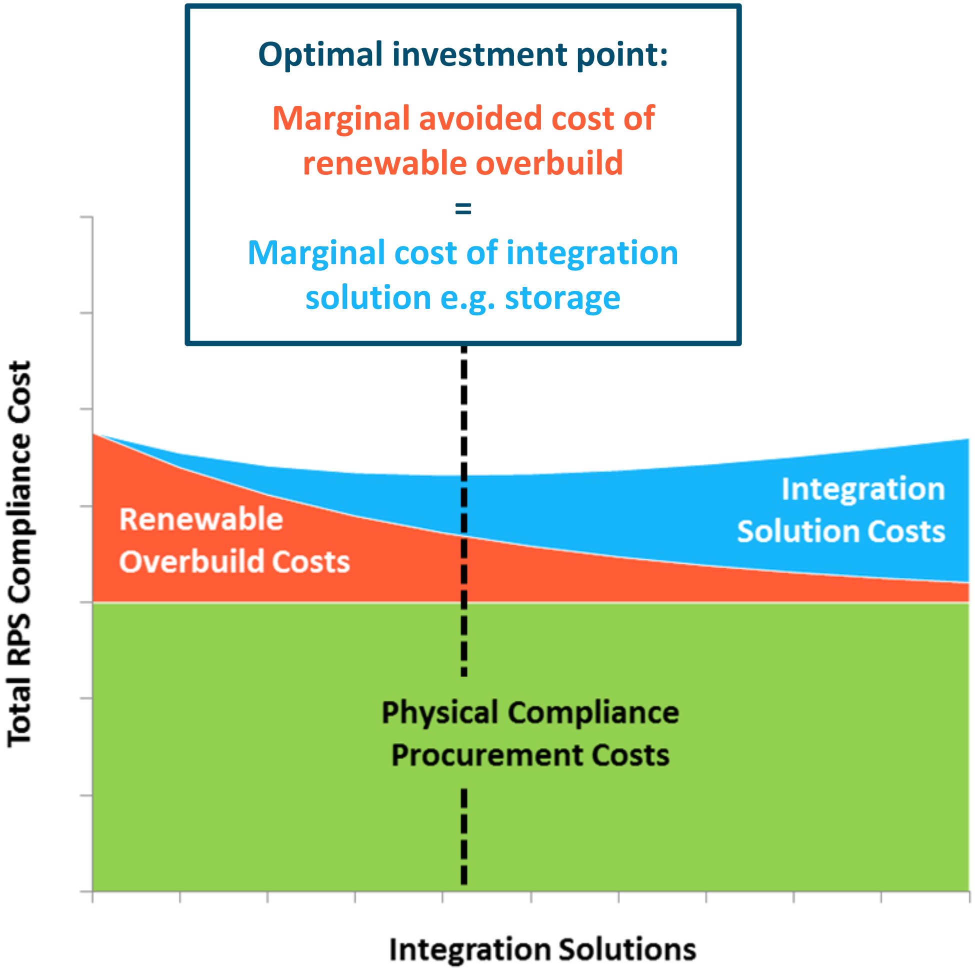
+ **Similar question to which type of coffee is more expensive – how often do you drink coffee?**

vs.

New Trends in Resource Planning

+ **New constraints added to the optimization**
  - Emission targets/caps
  - Emission taxes
  - Renewable energy targets
+ **Complexities associated with modeling variable renewable energy sources and storage with limited duration**



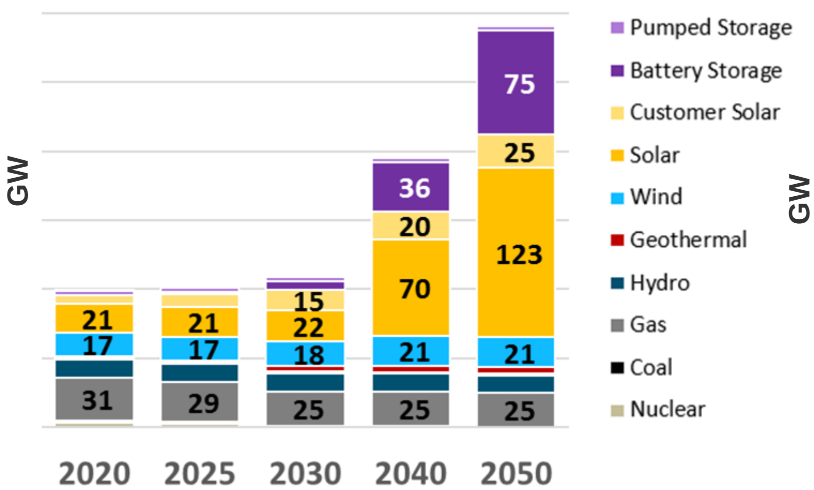


Capacity Expansion Modeling

- A new class of "capacity expansion" models are emerging that can accurately incorporate the complex challenges associated with renewables, hydro, storage, and other demand-side resources
- These models can develop least-cost portfolios that simultaneously satisfy constraints such as reliability and emission/renewable targets

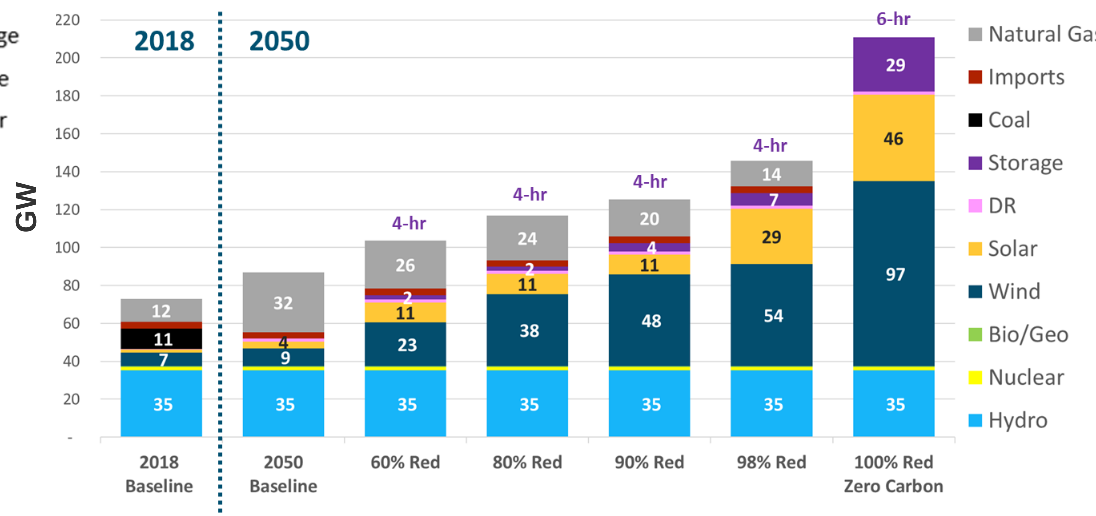
California Case Study

80% Decarbonization



Pacific Northwest Case Study

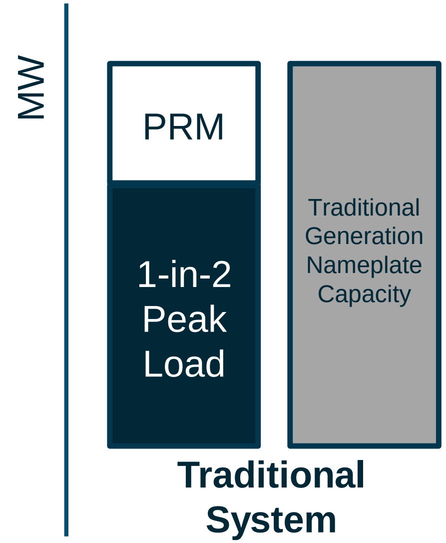
Various Decarbonization Targets



Source: E3 RESOLVE/RECAP

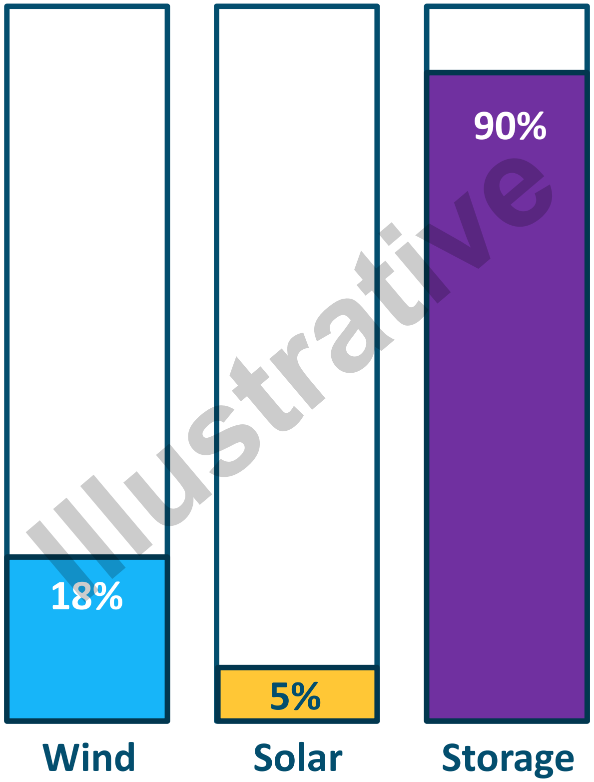
Planning Reserve Margin (PRM)

+ **Planning reserves are resources held by the utility above the forecasted median peak load that help maintain reliability even in the event of:**
  - Unplanned forced generator outages
  - Higher than normal peak loads (very cold weather)
  - Operating reserve requirements
+ **PRM is a convention that is typically based on:**
  - Installed capacity of traditional generation vs. 1-in-2 median peak load (e.g. half of the years experience a peak load higher than this and half lower)
+ **PRMs vary by utility but typically range from 12%-20+% depending on system characteristics**
  - Larger systems with more load and resource diversity can generally maintain lower PRMs
  - Islanded systems with limited interconnections and load and resource diversity such as Hawaii must maintain a PRM around 40%



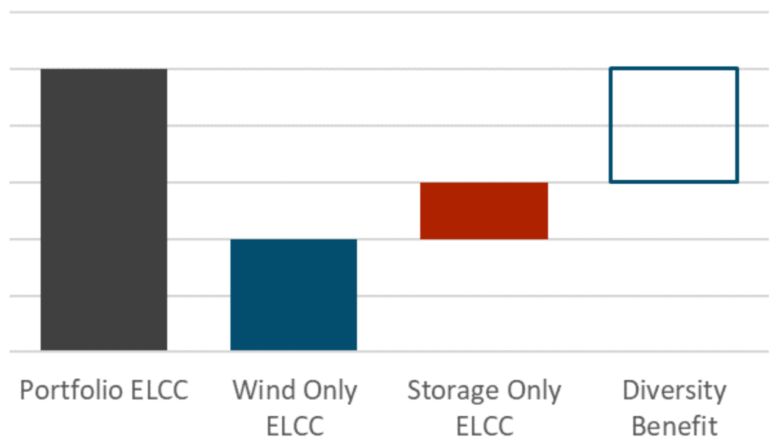
Renewable/Storage Contribution to PRM

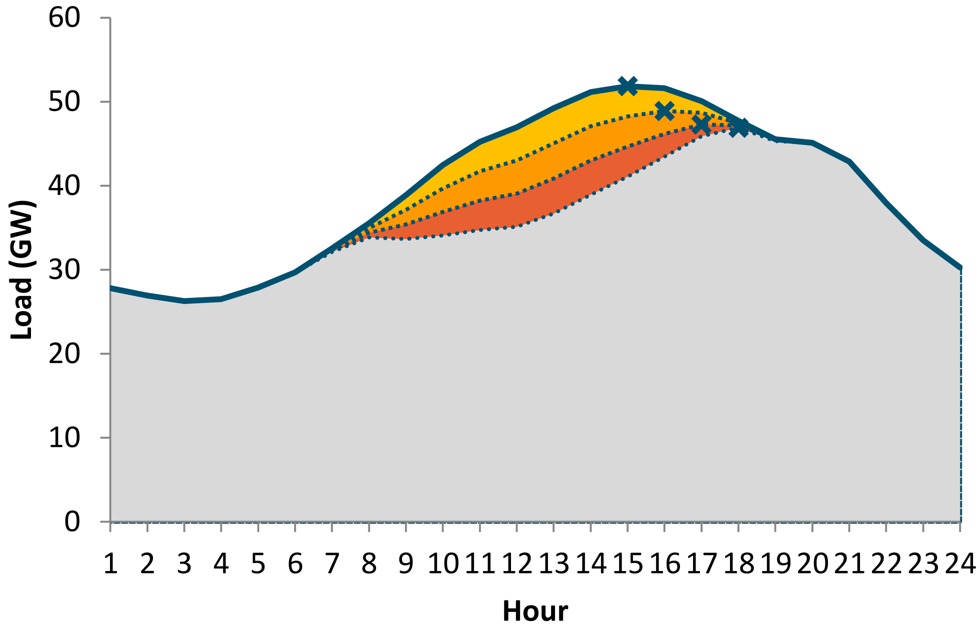
- In systems with high penetrations of renewable energy and storage, utilities must still maintain acceptable reliability through a planning reserve margin
- Effective load carrying capability (ELCC) measures a resource's ability to contribute to PRM
- ELCC is the quantity of "perfect capacity" that could be replaced or avoided with renewables or storage while providing equivalent system reliability
  - A value of 50% means that the addition of 100 MW of that resource could displace the need for 50 MW of firm capacity without compromising reliability
- Calculating ELCC requires computationally intensive models that can accurately account for the correlation and probability of production between load and renewables

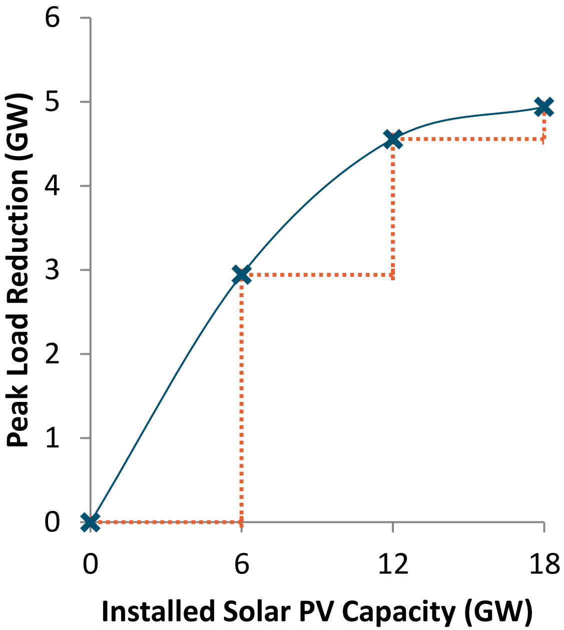


Diminishing Marginal ELCC and Diversity Benefits of Renewables/Storage

- The ELCC of renewables or storage depends on the other resources on the system
- The diminishing marginal peak load impact of solar PV is illustrative of this concept
- There are also diversity benefits between resources such that the total contribution of a portfolio of resources may be more than the sum of their parts

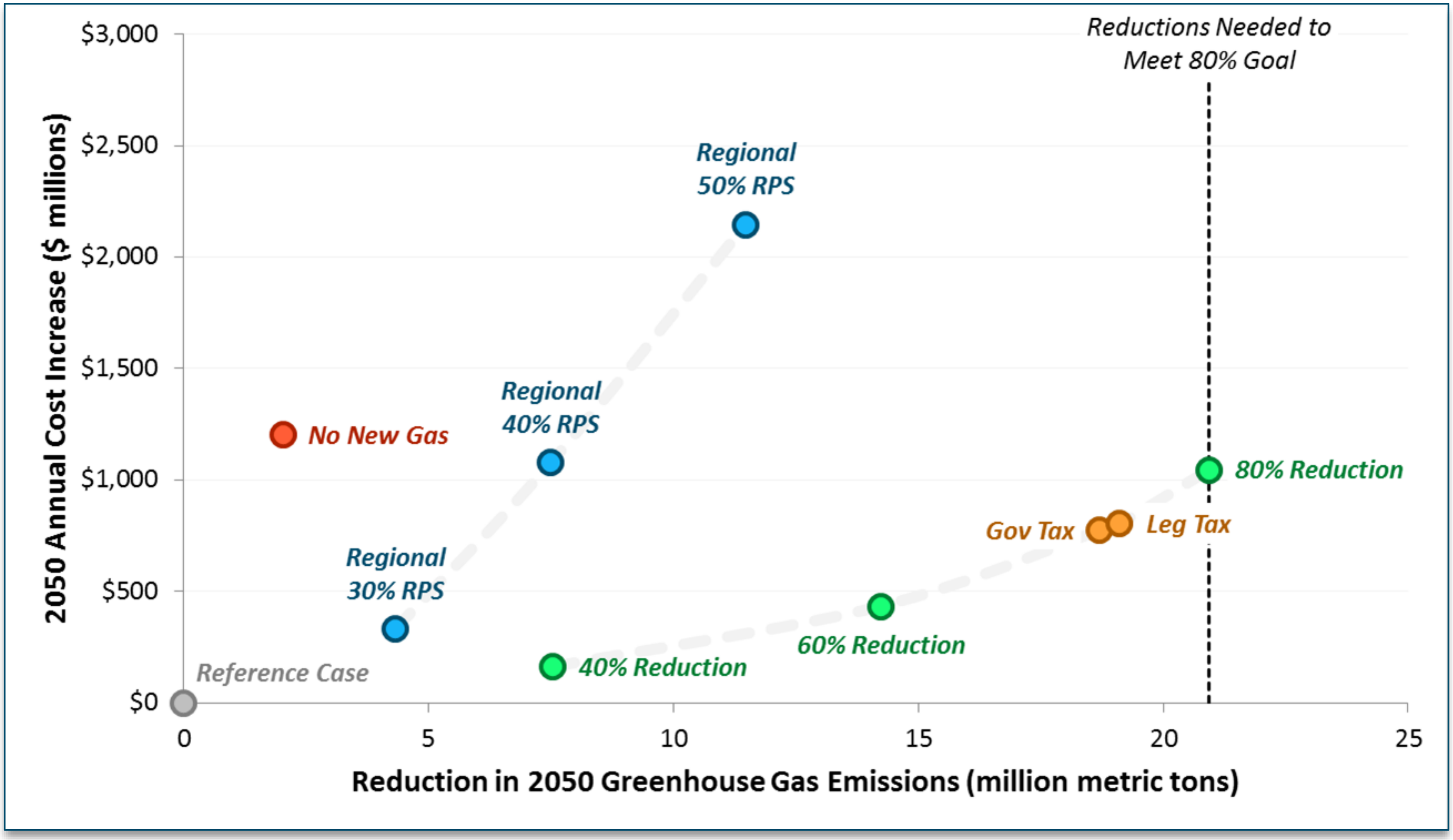






Putting it All Together

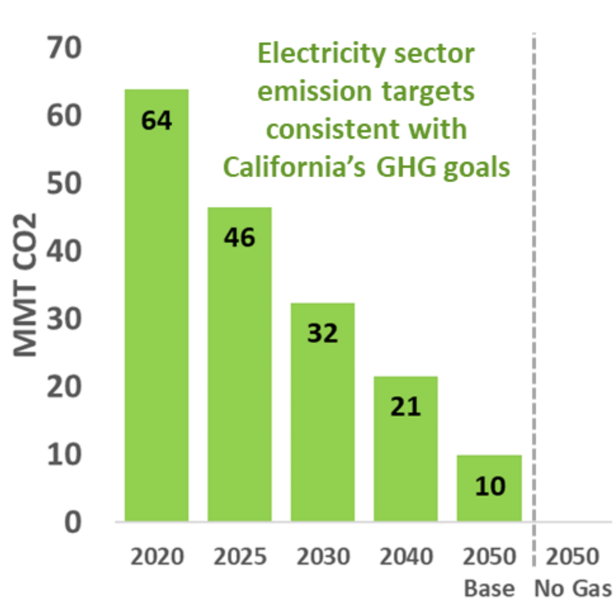
+ **IRP must accurately evaluate the energy, capacity, and emission requirements and construct a portfolio of resources that satisfy these constraints at least-cost**



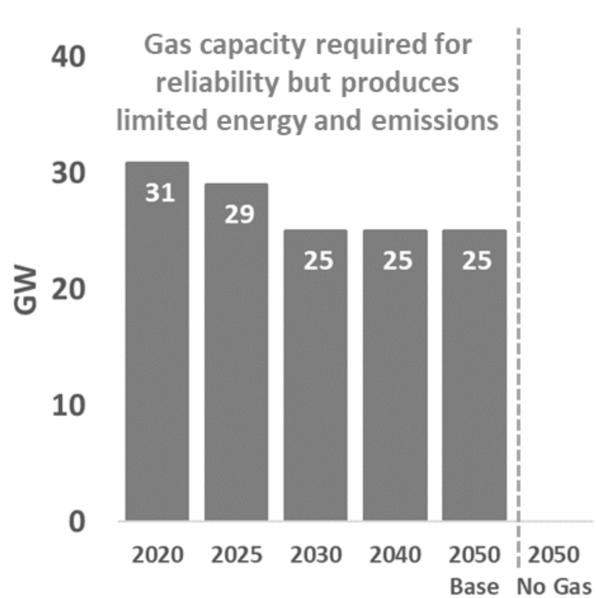
Key Challenges for California

- Least-cost plan for achieving 2050 economy-wide goals of 80% GHG reductions below 1990 levels requires electricity-sector reductions of 90-95%
- Significant quantities of renewables + storage is required, but firm capacity is still needed for reliability
- Natural gas is the most economic source of firm capacity

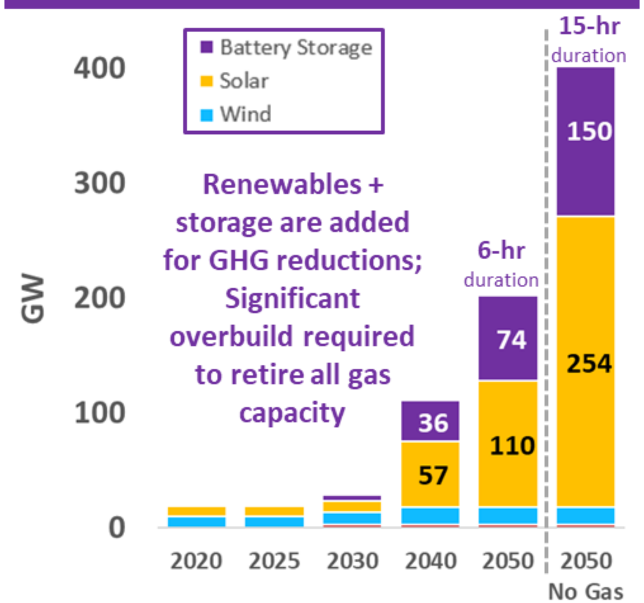
Emission Targets



Gas Capacity

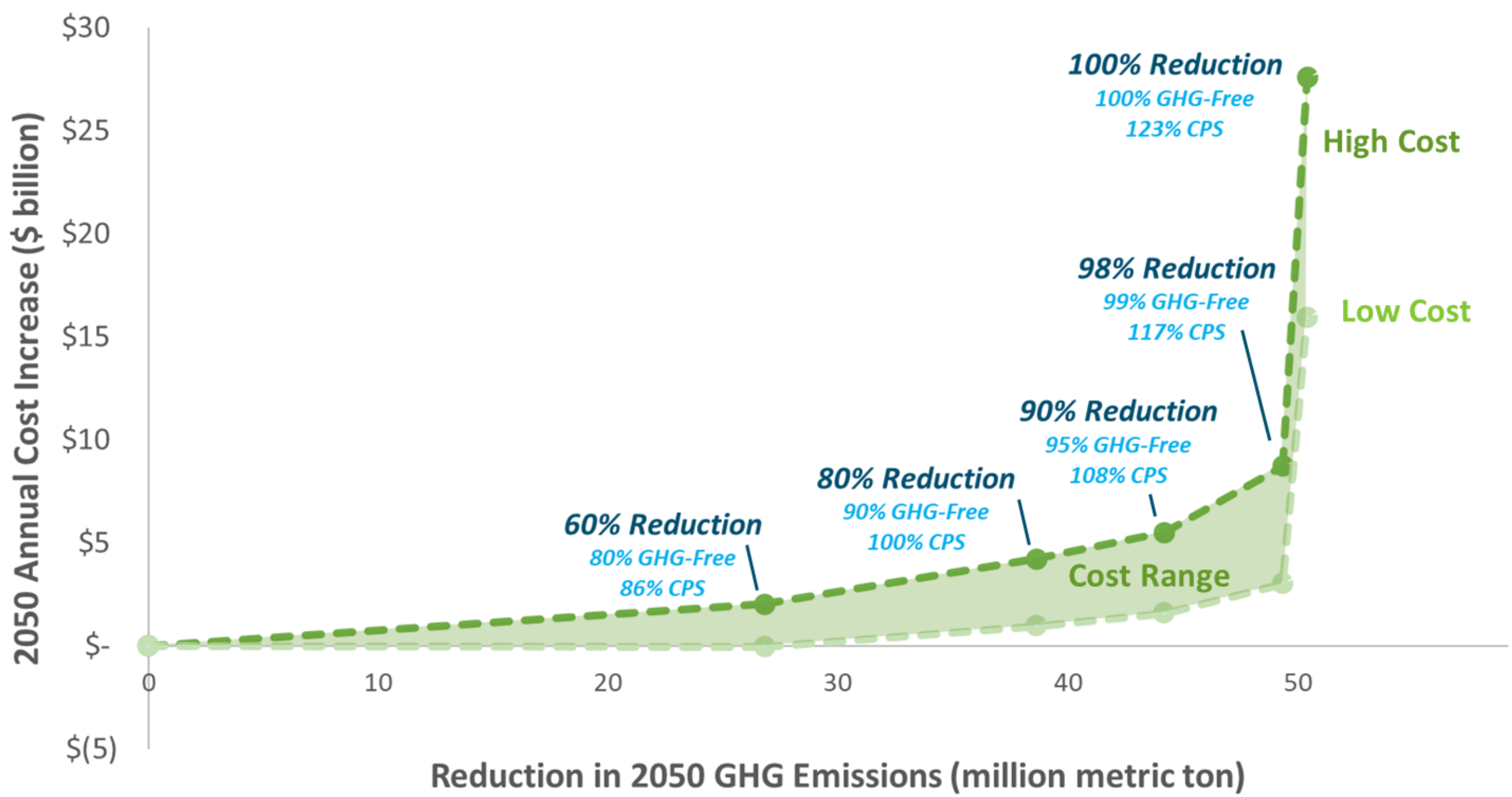


New Resources



Key Challenges for the Pacific Northwest

- **Significant quantities of renewables + storage is required to achieve GHG reductions, but firm capacity is still needed for reliability**
  - Due to retirement of coal, new natural gas capacity is part of a least-cost portfolio up to 98% GHG reductions
- **Replacing all firm capacity with renewables + storage only (100%) is extremely costly due to overbuild and curtailment**



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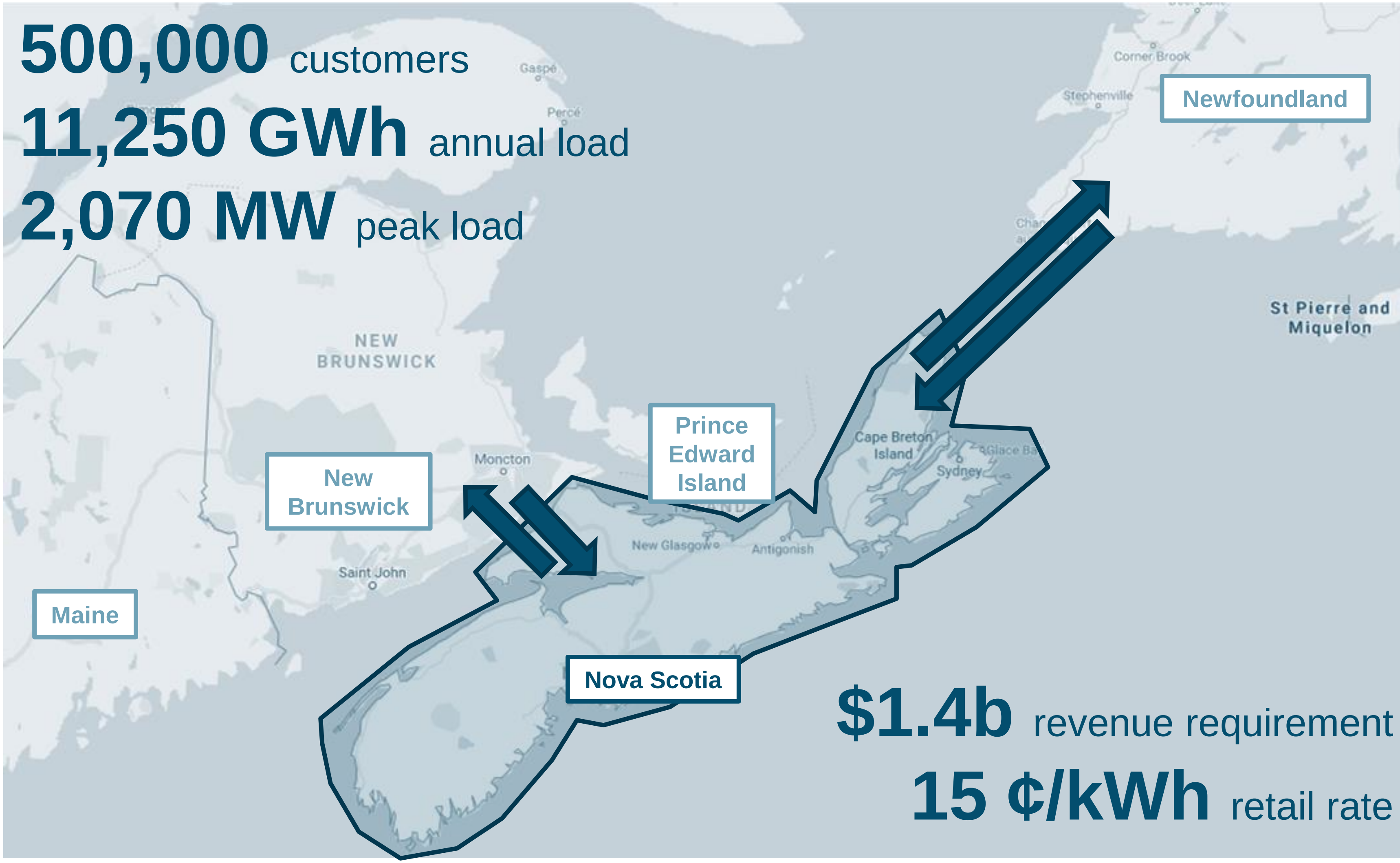
NSPI System Overview and Coming Challenges

Overview of Nova Scotia System

500,000 customers

11,250 GWh annual load

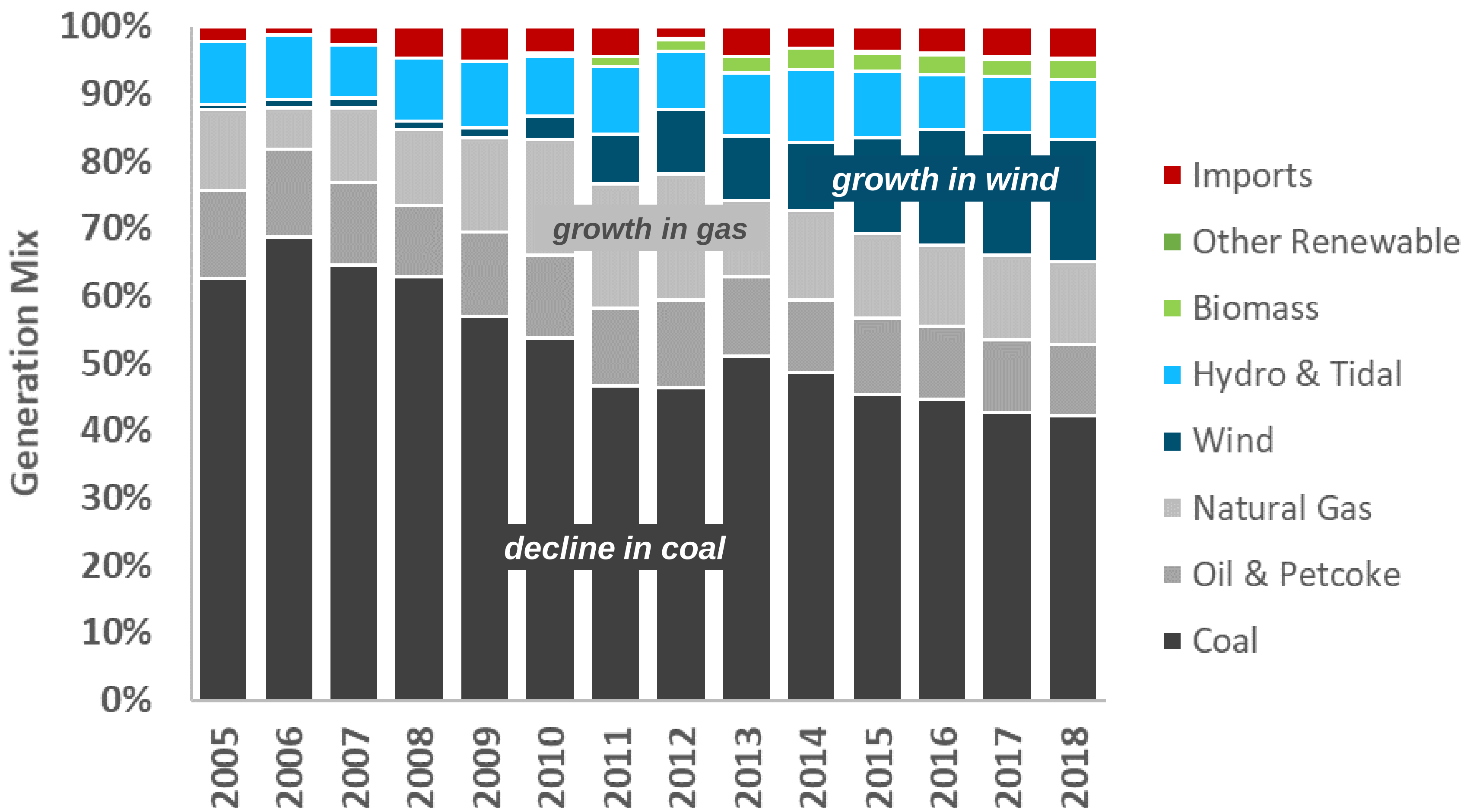
2,070 MW peak load



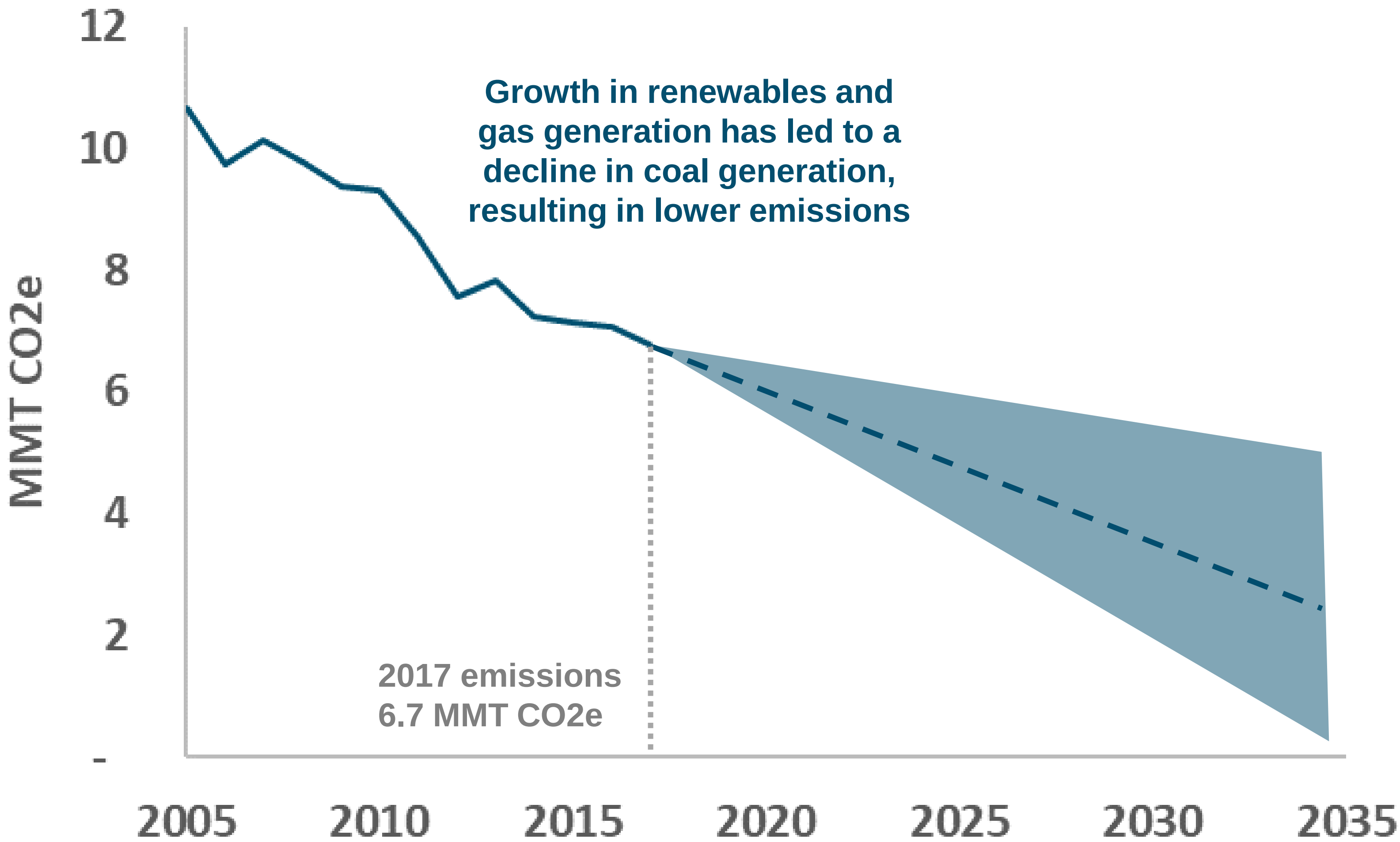
$1.4b revenue requirement

15 ¢/kWh retail rate

Generation Mix in Nova Scotia



GHG Emissions in Nova Scotia



NSPI Load and Resources

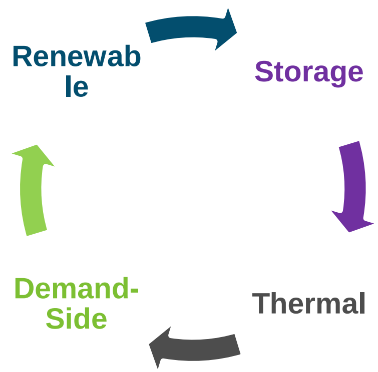
Load		NSPI 10-Yr Outlook	
Firm Peak Load Net of DSM (MW)		2016	
Target Reliability Standard		0.1 days/year	
Target PRM		20%	
Total Requirement (MW)		**2,419**	
Resources	**Nameplate MW**	**Net Capacity (MW)**	**ELCC %**
Coal	1081	1081	100%
Oil	231	231	100%
Natural Gas/Heavy Fuel Oil	462	462	100%
Biomass/Biogas	76	76	100%
Run-of-River Hydro	162	162	100%
Wreck Cove Hydro	212	212	100%
Annapolis Tidal	19	3.5	18%
Feed-in-Tariff Tidal	6.5	1.3	20%
Wind	596	101	17%
Solar	1.7	0	0%
New COMFIT Renewables	179.1	16.3	9%
Maritime Link Base Energy Imports	153	153	100%
Total Supply (MW)	**3,179**	**2,499**	

Key Nova Scotia Challenges

Portfolio Optimization

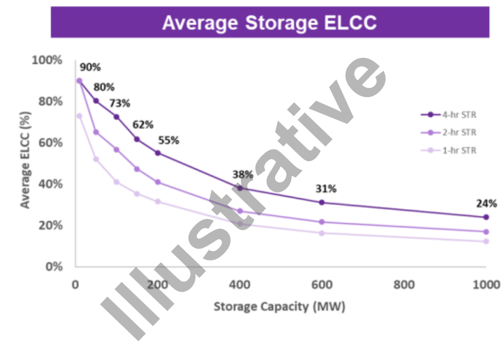
Determining the optimal portfolio of renewable, hydro, storage, thermal, and demand-side resources

All resources have limitations and unique characteristics and a least-cost portfolio reflects this



Firm Capacity

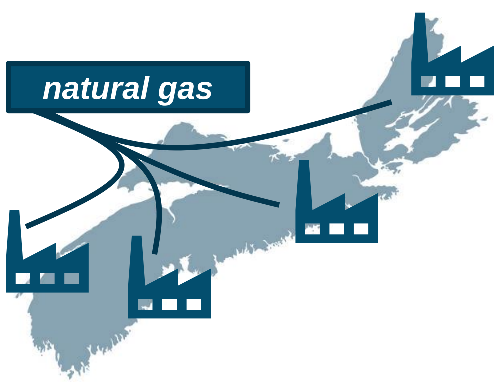
Maintaining adequate firm capacity for reliability considering potential coal retirements and the limitations of non-thermal resources



Firm Fuel

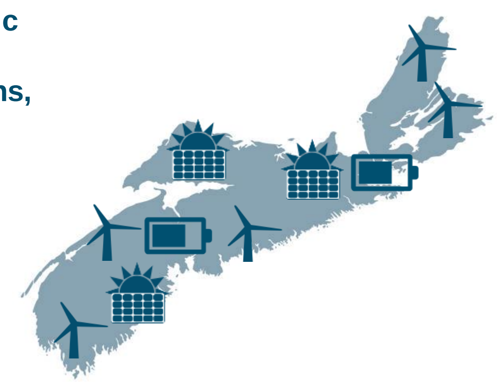
Ensuring firm fuel for new thermal resources despite limited pipeline capacity to Nova Scotia

Peak electricity loads correlate with peak natural gas demand for heating which constrains pipeline availability



Renewable Integration

Given the limited electric interconnections with neighboring jurisdictions, ensuring that higher penetrations of renewable energy maintains system stability, inertia, and other essential grid services



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Thank You

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Arne Olson, Sr. Partner (arne@ethree.com)

NSP PRE-IRP DELIVERABLES

1. Capacity Study

DESCRIPTION:
Consultant LOLE study which calculates the required Planning Reserve Margin, wind capacity value, and requirements for storage durations for capacity for the NSP system.

DELIVERABLE TYPE: Report

STATUS: ON TRACK

2. Supply Options Study

DESCRIPTION:
Consultant study which estimates the initial and sustaining costs and performance of new bulk grid supply options and future trends. NSP study of expected sustaining capital and performance of existing assets.

DELIVERABLE TYPE: Report

STATUS: ON TRACK

NSP PRE-IRP DELIVERABLES

3. Demand Response Assumptions
DESCRIPTION: Draft modeling assumptions (cost and load impacts) for 1 to 3 specific DR programs.
DELIVERABLE TYPE: Assumptions Deck
STATUS: ON TRACK

4. Renewables Stability Study
DESCRIPTION: Consultant report identifying transmission requirements and system design considerations for increased levels of renewables on the NSP grid based on technical system studies.
DELIVERABLE TYPE: Report
STATUS: ON TRACK

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PRE-IRP DELIVERABLES STAKEHOLDER DISCUSSION

AUGUST 7, 2019

Nova Scotia POWER An Emera Company

TODAY'S AGENDA

1. Introduction to Pre-IRP Deliverables

2. Overview & Discussion of each Deliverable:

   I. **CAPACITY STUDY**
   II. **SUPPLY OPTIONS STUDY**
   III. **RENEWABLES STABILITY STUDY**
   IV. **DR PROGRAM ASSUMPTIONS DEVELOPMENT**

3. Discuss Next Steps

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INTRODUCTION TO PRE-IRP DELIVERABLES

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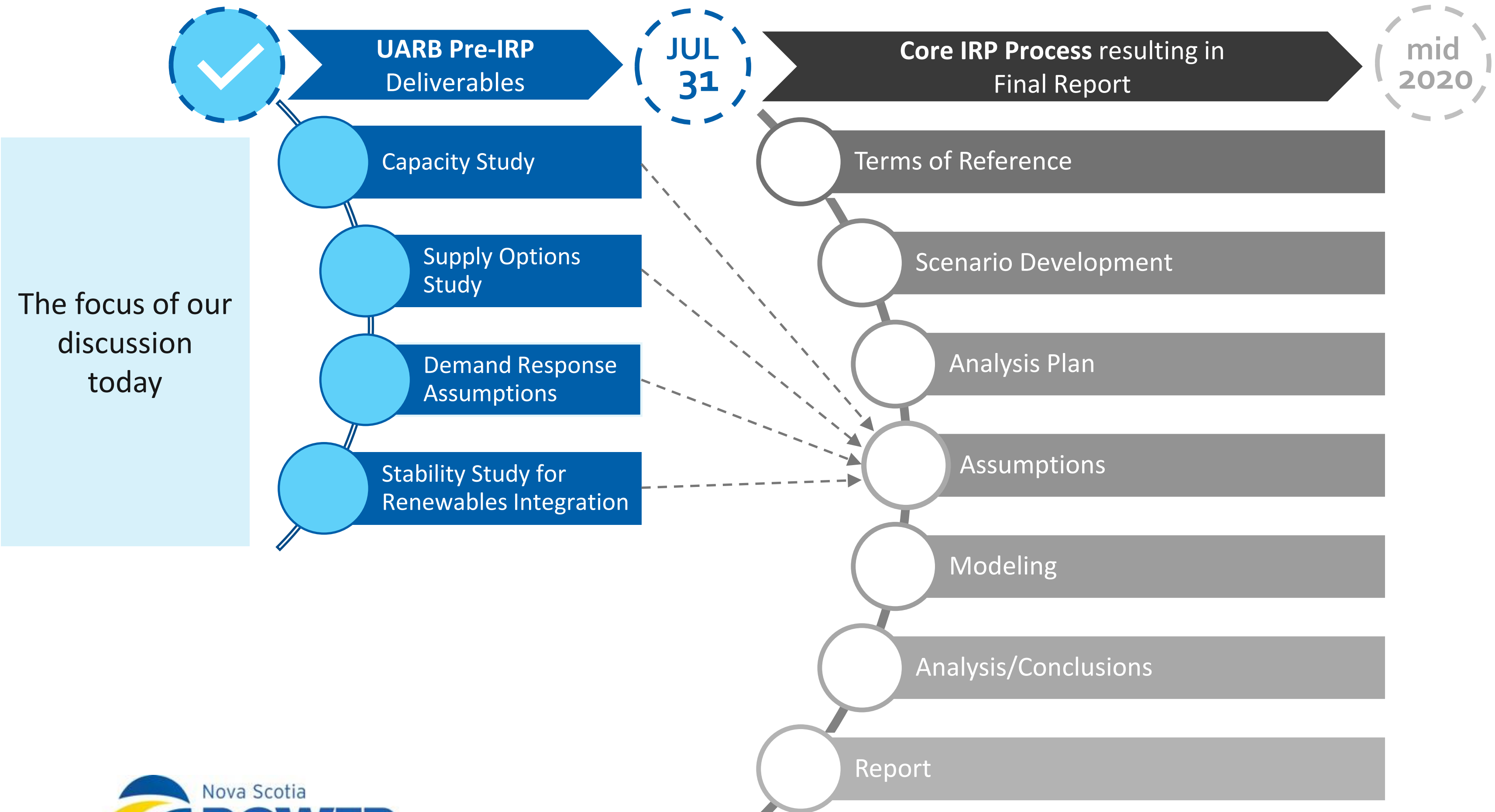
IRP PROCESS OVERVIEW



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INTRODUCTION TO MATERIALS

- All Pre-IRP deliverables are provided as drafts for discussion and feedback. These deliverables will form the primary basis for many of the key IRP Assumptions.
- Our plan is to address feedback either via revision/iteration on these deliverables (in time to be finalized by the Assumptions Development phase), or to design appropriate Scenarios and/or Sensitivities in the Analysis Plan to capture stakeholder feedback.

Draft Pre-IRP Materials
- Workshops
- Stakeholder Feedback

Address Feedback
- Revise & iterate on deliverables
- Add considerations to Analysis Plan or Scenarios

IRP
- Draft Analysis Plan
- Draft Assumptions for review & discussion

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KEY CONSIDERATIONS FOR THIS IRP

As discussed in the workshop on June 28, 2019, there are many additional factors in the planning environment at this time to consider for this IRP; in particular there is uncertainty around:

- Environmental Policy
- Provision of Essential Grid/Reliability Services
- Distributed Energy Resources
- Cost and capability of new technologies
- Customer behaviour and trends (e.g. electric vehicles, rooftop solar)
- Firm fuel supply sources

Our objective is to develop an Analysis Plan that captures consideration of the above and to facilitate further discussion with stakeholders on these issues to form conclusions/recommendations as appropriate in the IRP.

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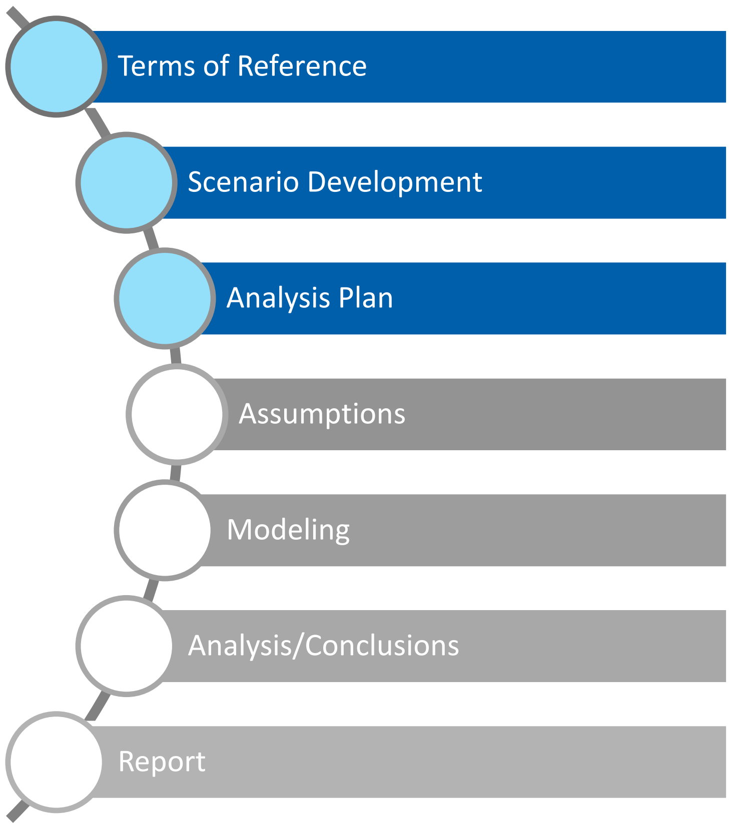
IRP OBJECTIVES IN A DYNAMIC PLANNING ENVIRONMENT



Consideration of objectives and process changes will be part of further discussion through development of the TOR and Analysis plan.

For example:

- Should IRP objectives move beyond "least cost NPV Revenue Requirement"?
- How do we consider decarbonization?
- How do we ensure "no regrets" given the significant uncertainty we face?

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ESSENTIAL GRID/RELIABILITY SERVICES

Of particular importance in modeling scenarios with high penetration of renewables and/or significant thermal generation retirements is the provision of essential grid/reliability services (and the associated costs of obtaining them).

NS Power will work with stakeholders through the Assumptions Development and Modeling Phases to better understand these opportunities and challenges.

Resource Type	Essential Grid/Reliability Service							
	Energy	Firm Capacity	Operating Reserves	Inertia	Frequency Response	Reactive Power/ Voltage Control	Black Start	Etc.
Thermal Unit	Provides	Provides	Provides	Provides	Provides	Provides	None	
Combustion Turbine	Partially Provides	Provides	Provides	Provides	Provides	Provides	Provides	
Hydro	Provides	Provides	Provides	Provides	Provides	Provides	Provides	
Wind	Provides	Partially Provides	Potential to Provide	None	Partially Provides	Partially Provides	None	
Solar	Provides	None	Potential to Provide	None	None	None	None	
Battery Storage	None	Partially Provides	Provides	None	Provides	Provides	Provides	
Demand Response	Partially Provides	Partially Provides	Provides	None	None	None	None	

ILLUSTRATIVE EXAMPLE ONLY

Provides	(green)
Partially Provides	(light blue)
None	(grey)
Potential to Provide	(dark blue)

These services are all critical for a stable, reliable grid – but not all resources can provide them.

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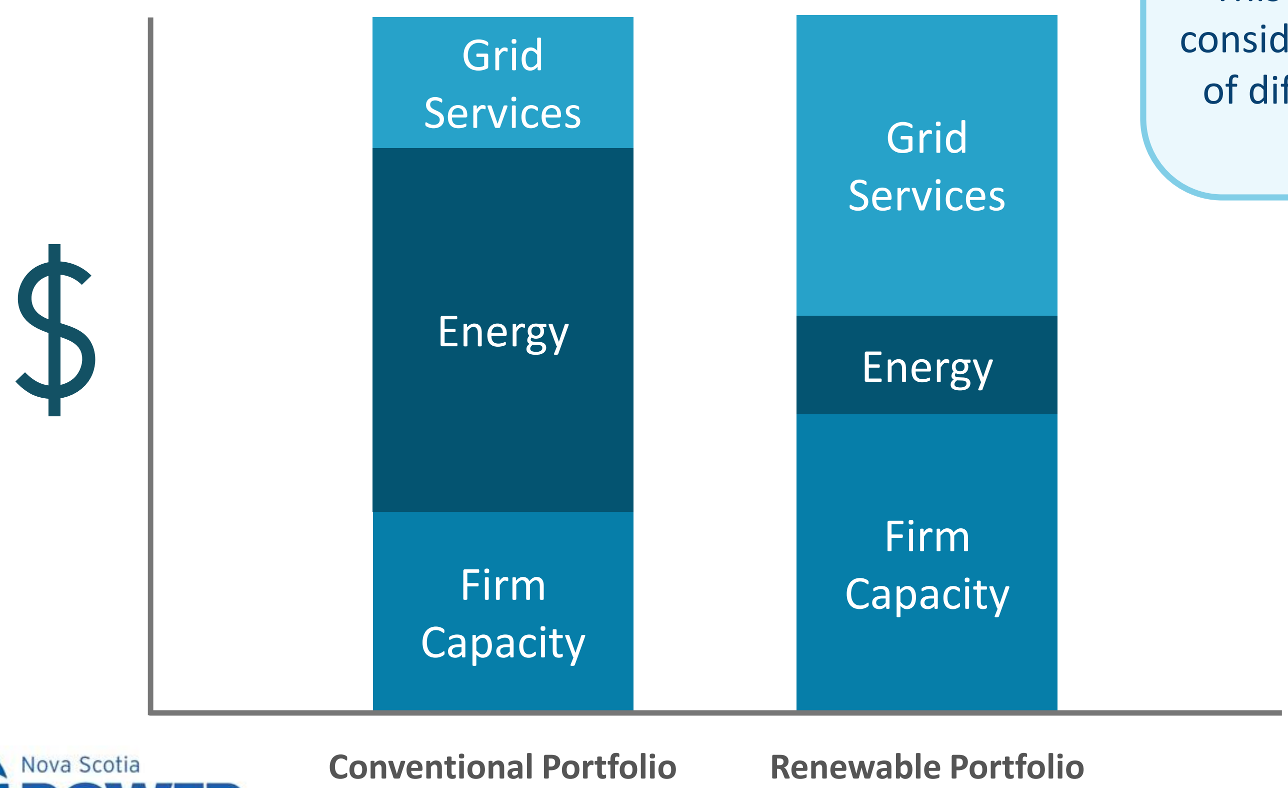
WHY DO ESSENTIAL GRID SERVICES MATTER?

ILLUSTRATIVE EXAMPLE:
PORTFOLIO COST DISTRIBUTION



The proportions of the costs to serve the needs of customers can change depending on the resource mix.

This is important to consider in the full cost of different portfolio options.

CAPACITY STUDY:
OVERVIEW & DISCUSSION

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Overview of PRM Study

Nova Scotia Power Inc.

August 7, 2019

Zach Ming, Sr. Managing Consultant

Study Objectives

+ **The Planning Reserve Margin (PRM) study provides an update to several assumptions to be used by Nova Scotia Power Inc. (NSPI) in the integrated resource planning (IRP) process**
+ **PRM study outline**
  - Background + jurisdictional review of industry best practices
  - Overview of analytical approach & assumptions: E3 RECAP model
  - Calculation of required PRM for NSPI to meet target reliability standard
    - Loss of Load Expectation (LOLE) of 1 day in 10 years (0.1 days/yr)
  - Calculation of existing and potential effective load carrying capability (ELCC) for various dispatch-limited resources
    - Wind
    - Solar
    - Storage
    - Demand Response

Planning Reserve Margin (PRM)

+ **Planning reserves are resources held by the utility above the forecasted median peak load that help maintain reliability even in the event of:**
  - Unplanned forced generator outages
  - Higher than normal peak loads (very cold weather)
  - Operating reserve requirements
+ **PRM is a convention that is typically based on:**
  - Installed capacity of traditional generation vs. 1-in-2 median peak load (e.g. half of the years experience a peak load higher than this and half lower)
+ **PRMs vary by utility but typically range from 12%-20+% depending on system characteristics**
  - Larger systems with more load and resource diversity can generally maintain lower PRMs
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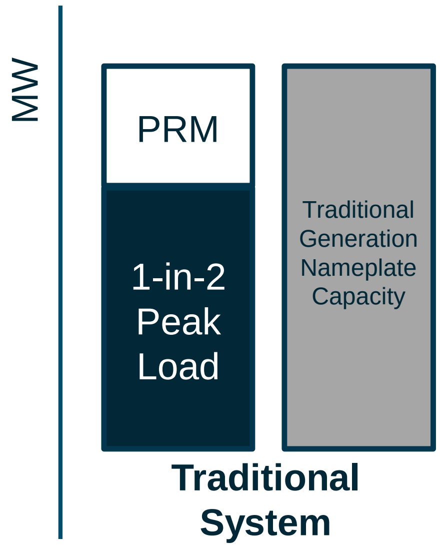

Reliability Planning Process

Step 1: **Reliability Standard (1-day-in-10-years)** → **Step 2**: **Target Planning Reserve Margin**

Renewable/Storage Contribution to PRM

- In systems with high penetrations of renewable energy and storage, utilities must still maintain acceptable reliability through a planning reserve margin
- Effective load carrying capability (ELCC) measures a resource's ability to contribute to PRM
- ELCC is the quantity of "perfect capacity" that could be replaced or avoided with renewables or storage while providing equivalent system reliability
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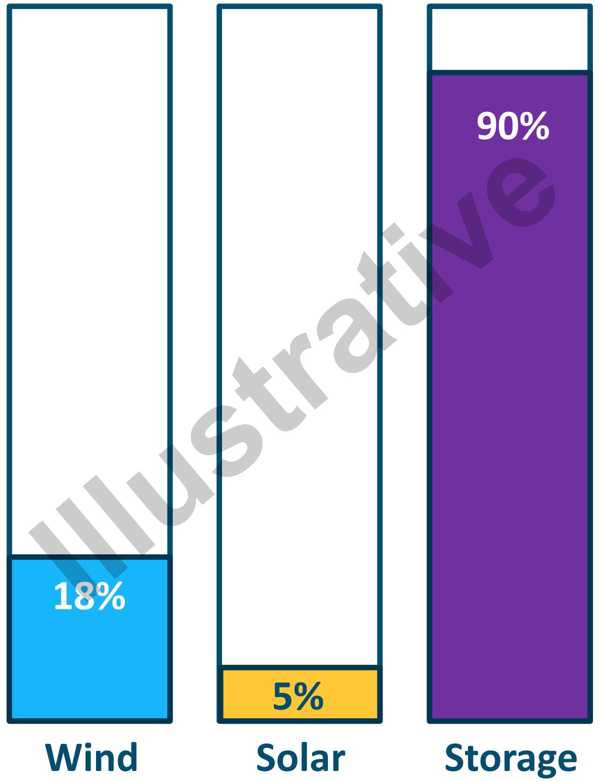

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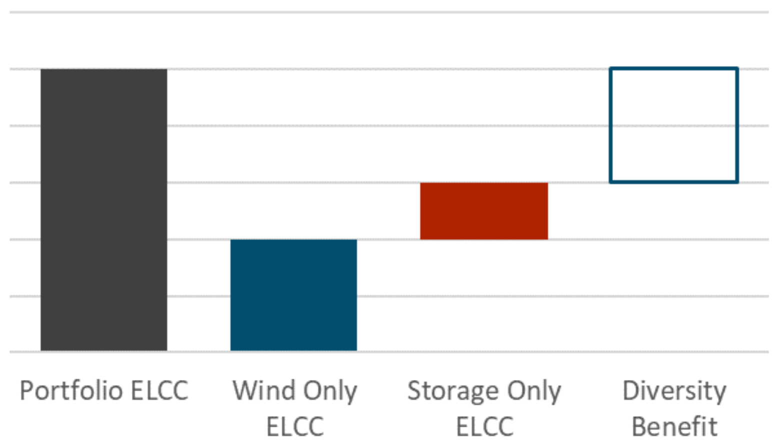

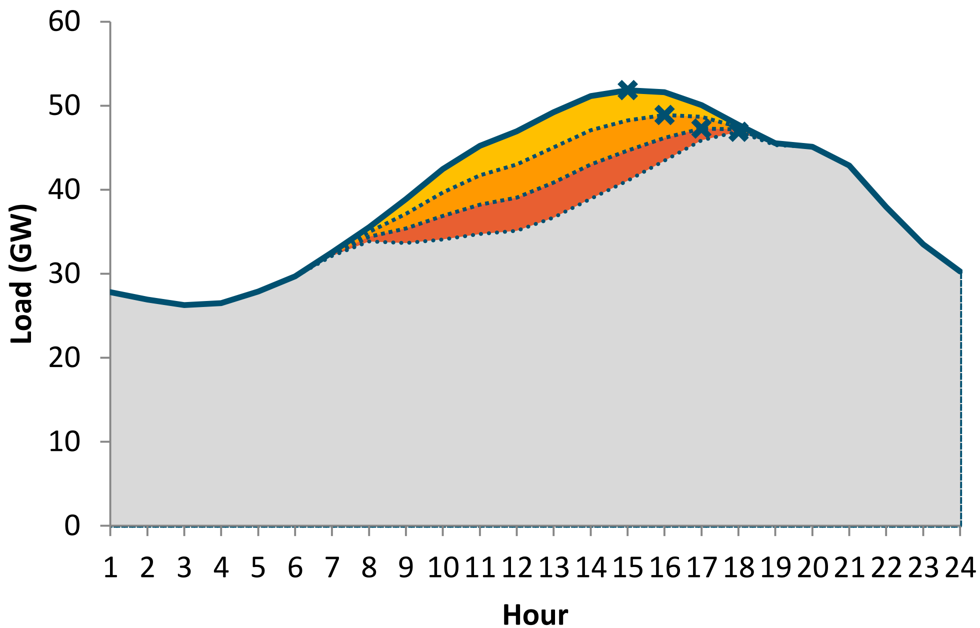

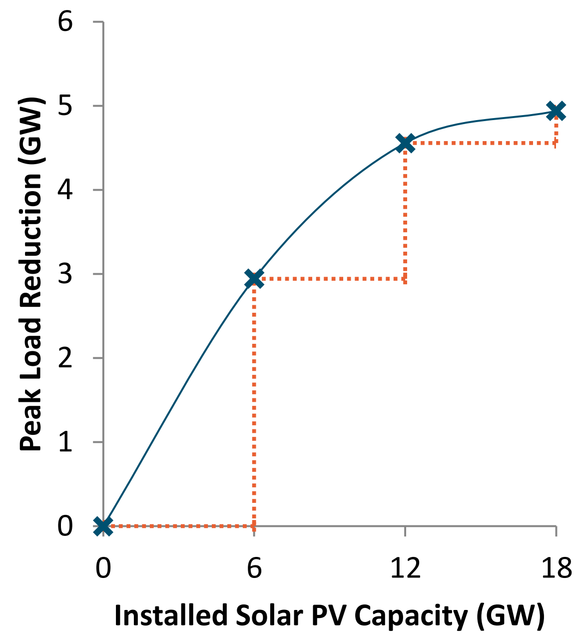

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Jurisdictional Review

Overview of Jurisdictional Review

+ **E3 conducted a review of reliability standards and planning practices mainly across several North American electric jurisdictions**
  - Reliability metrics and targets used for planning
  - How reliability metrics are converted into planning practices e.g. PRM values
  - PRM metric conventions i.e. de-ratings for forced outages

+ **Ultimate conclusion was that NSPI is in-line with industry best practices for reliability planning**
  - NSPI plans to a 1-day-in-10 year standard or 0.1 days/yr loss of load expectation (LOLE)

Jurisdictional Summary

Jurisdiction / Utility	Reliability Metric	Metric Value	Notes
AESO	EUE	800 MWh/year (0.0014%)	AESO monitors capacity and can take action if modeled EUE exceeds threshold; 34% PRM achieved in 2017 w/o imports
CAISO	PRM	15%	No explicit reliability standard
ERCOT	N/A	N/A	Tracks PRM for information purposes; "Purely information" PRM of 13.75% achieves 0.1 events/yr; Economically optimal = 9.0%; Market equilibrium = 10.25%
Florida	LOLE	0.1 days/year	15% PRM required in addition to ensuring LOLE is met
ISO-NE	LOLE	0.2/0.1/0.01 days/year	Multiple LOLE targets are used to establish demand curve for capacity market
MISO	LOLE	0.1 days/year	7.9% UCAP PRM; 16.8% ICAP PRM
Nova Scotia	LOLE	0.1 days/year	20% PRM to meet 0.1 LOLE standard
NYISO	LOLE	0.1 days/year	LOLE is used to set capacity market demand curve; Minimum Installed Reserve Margin (IRM) is 16.8%; Achieved IRM in 2019 is 27.0%
PacifiCorp	N/A	N/A	13% PRM selected by balancing cost and reliability; Meets 0.1 LOLE
Hawaii (Oahu)	LOLE	0.22 days/yr	Relatively small system size and no interconnection results in 45% PRM
PJM	LOLE	0.1 days/year	LOLE used to set target IRM (16%) which is used in capacity market demand curve
SPP	LOLE	0.1 days/year	PRM assigned to all LSE's to achieve LOLE target: 12% Non-coincident PRM & 16% Coincident PRM
Australia	EUE	0.002%	System operator monitors forecasted reliability and can intervene in market if necessary
Great Britain	LOLH	3 hours/year	5% (Target PRM 2021/22) 11.7% (Observed PRM 2018/19)
Ireland	LOLH	8 hours/year	LOLH determines total capacity requirement (10% PRM) which is used to determine total payments to generators (Net-CONE * PRM)

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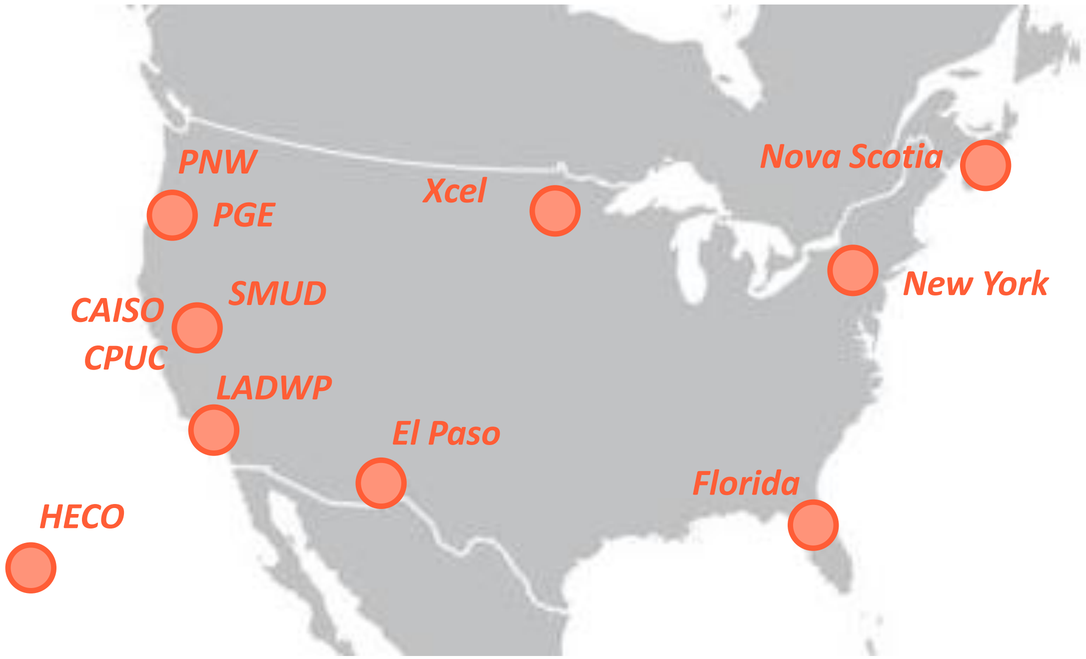
RECAP Model Overview & Assumptions

E3 Renewable Energy Capacity Planning Model (RECAP)

+ **RECAP is a loss-of-load-probability (LOLP) model for evaluating power system reliability for high penetration scenarios**
+ **Initially developed to support the California ISO with renewable integration modeling more than 10 years ago**
+ **Has been progressively updated and used by a number of utilities and regulators across North America**
  - CPUC
  - Portland General Electric
  - SMUD
  - WECC
  - LADWP
  - Florida Power & Light
  - El Paso Electric
  - Pacific Northwest
  - Nova Scotia Power
  - Xcel Minnesota
  - HECO



RECAP: E3's Renewable Energy Capacity Planning Model

+ **RECAP is a loss-of-load probability (LOLP) model used to test the resource sufficiency of electricity system portfolios**
  - This study uses a 1-day-in-10-year standard (0.1 days/yr LOLE) to determine the target PRM

+ **RECAP evaluates sufficiency through time-sequential simulations over thousands of years of plausible load, renewable, and stochastic forced outage conditions**
  - Captures thermal resource and transmission forced outages
  - Captures variable availability of renewables & correlations to load
  - Tracks hydro and storage state of charge

Inputs

Load
- *Hourly load for many weather years*

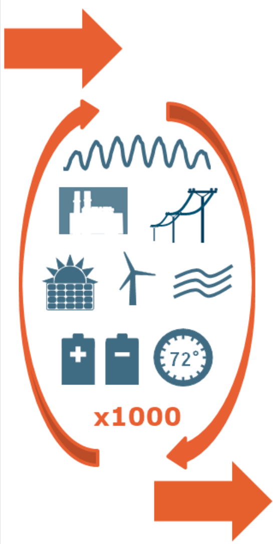
Dispatchable Generation
- *Capacity*
- *FOR*
- *Maintenance*

Renewables
- *Capacity*
- *Hourly generation profiles for many weather years*

Hydro
- *Hydro availability for many hydro years*
- *Max/min constraints*

Storage
- *Capacity*
- *Duration*
- *Roundtrip efficiency*
- *FOR*

Demand Response
- *Capacity*
- *Max # of calls*
- *Duration of each call*



Outputs

LOLE
- *Loss of load expectation*
- *Days/yr of total expected lost load per year*

LOLH
- *Loss of load hours*
- *Hours/yr of total expected lost load per year*

EUE
- *Expected unserved energy*
- *MWh/yr of energy that cannot be served*

ELCC
- *Effective load carrying capability*
- *Equivalent quantity of 'perfect capacity' for a variable or energy-limited resource*

TPRM
- *Target planning reserve margin*
- *PRM required to achieve a specified reliability threshold (i.e. LOLE, ALOLP, or EUE)*

RECAP Methodology

Step 1

Calculate Hourly Load

Step 2

Calculate Renewable Profiles

Step 3

Calculate Available Dispatchable Generation

Step 4

Hydro Dispatch

Step 5

Calculate Available Transmission

Step 6

Dispatch Storage

Step 7

Dispatch Demand Response

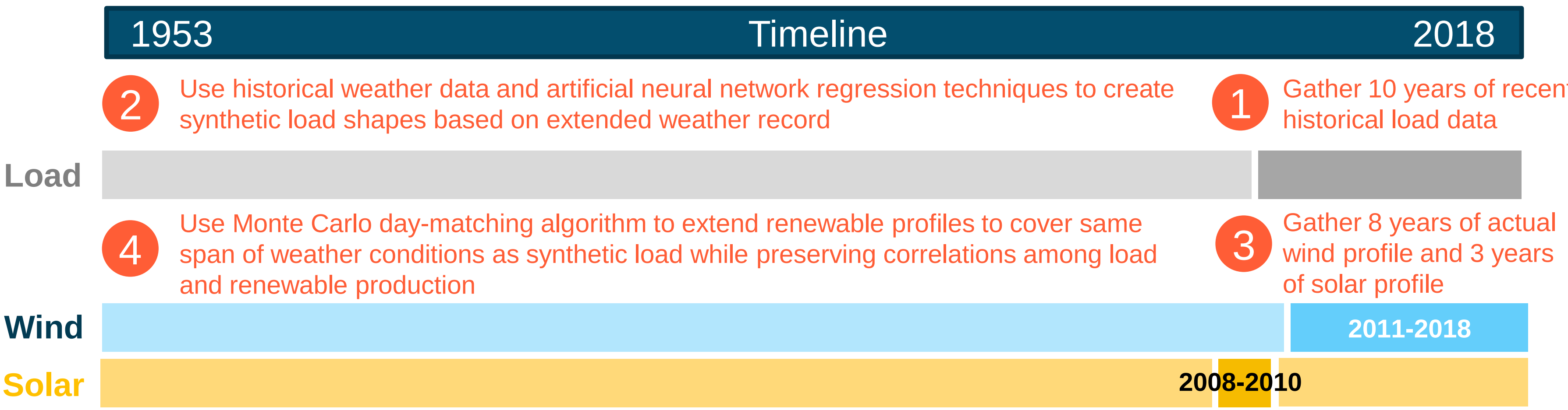
72°

Step 8

Calculate Loss of Load

Inputs for Load and Renewable Profiles

- Actual historical NSPI hourly load from 2009 to 2018
- Actual historical NSPI wind profiles from 2011 to 2018
- Simulated historical NSPI solar profiles from 2008 to 2010
- Weather and date information from 1953 to 2018



Dispatchable Resources in 2020

+ **E3 used the net operating capacity (MW) and DAFOR (%) to stochastically represent the dispatchable generating capability of these resources in the RECAP model**

Category	Fuel/Tech Type	Unit Name	Operating Capacity (MW)	DAFOR (%)
Conventional Thermal	HFO/N Gas	Tufts Cove 1	78	36.0%
		Tufts Cove 2	93	19.1%
		Tufts Cove 3	147	2.0%
		Tufts Cove 4	49	2.9%
		Tufts Cove 5	49	5.1%
		Tufts Cove 6	46	1.6%
	Coal/Petcoke	Pt Aconi	168	1.9%
		Lingan 1	153	1.7%
		Lingan 2	0	1.7%
		Lingan 3	153	4.2%
		Lingan 4	153	5.0%
		Trenton 5	150	6.8%
		Trenton 6	154	4.4%
		Tupper 2	150	1.9%
	Oil	Burnside 1	33	10.0%
		Burnside 2	33	10.0%
		Burnside 3	33	10.0%
		Burnside 4	33	10.0%
		Victoria Junction 1	33	10.0%
		Victoria Junction 2	33	10.0%
		Tusket	33	10.0%
Renewable	Hydro	Dispatchable Hydro	162	5%
	Biomass	Port Hawkesbury	43	1.2%
		IPP Biomass	31	1.2%
	Biogas	IPP Biogas	2	1.2%
Total Operating Capacity (MW)			**2,012**	

Hydro / Tidal Resources Overview

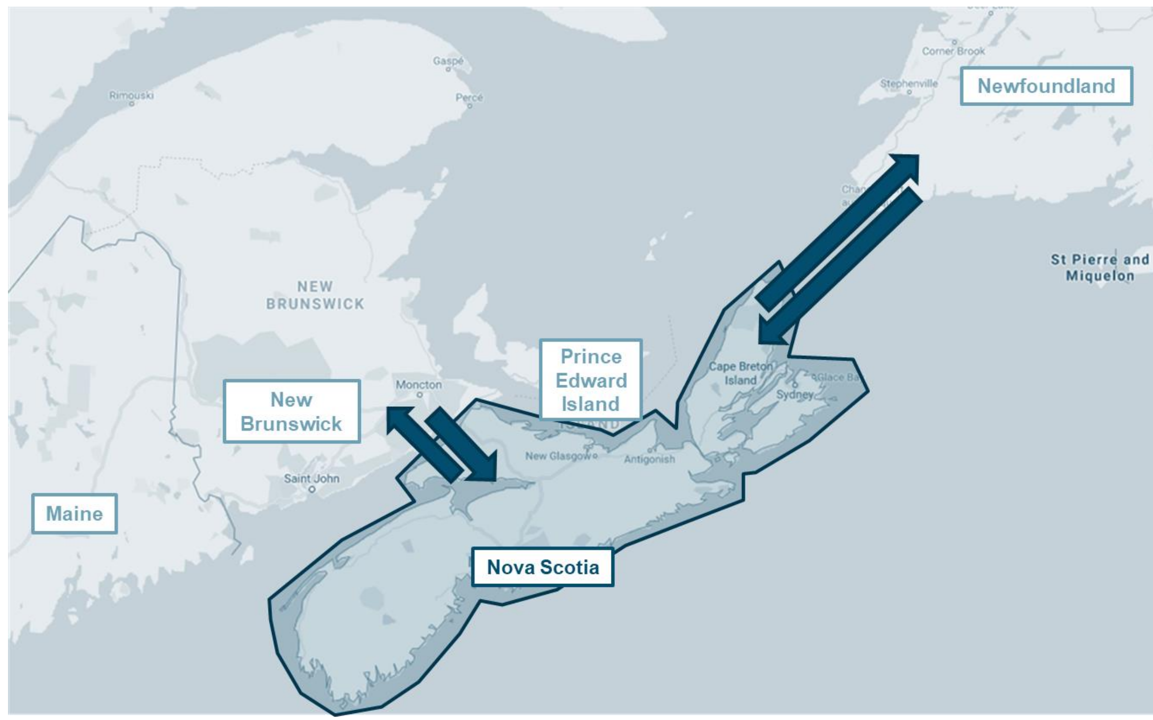
+ **For modeling purposes, hydro is grouped into 3 categories**
  - **Dispatchable:** hydro units can be dispatched at maximum output with no limit on duration
  - **Tidal:** Annapolis is modelled as resource with variable hourly profile similar to wind
  - **Wreck Cove:** Can be dispatched under constraints including maximum output, minimum output, and daily maximum energy

Hydro and Tidal Resources

Hydro Group	Resource Name	Maximum Capacity (MW)	Minimum Capacity (MW)	Other Constraints in RECAP
Firm Hydro	Tusket	2.4	0.9	Assumed to be available at maximum capacity during peak load hours
	St Margarets	10.8	0	
	Sheet Harbour	10.8	0.4	
	Dickie Brook	3.8	0.1	
	Nictaux	8.3	0	
	Lequille	11.2	0	
	Avon	6.75	0	
	Black River	22.5	6	
	Paradise	4.7	2	
	Mersey	42.5	6	
	Fall River	0.5	0	
	Sissiboo	24	6	
	Bear River	13.4	0	
Subtotal		162		
Tidal	Annapolis	19		Annual output profile
Subtotal		19		Daily Energy Budget (MWh)
Wreck Cove	Wreck Cove	212	0	500 - 1100
Subtotal		212		
Total		393		

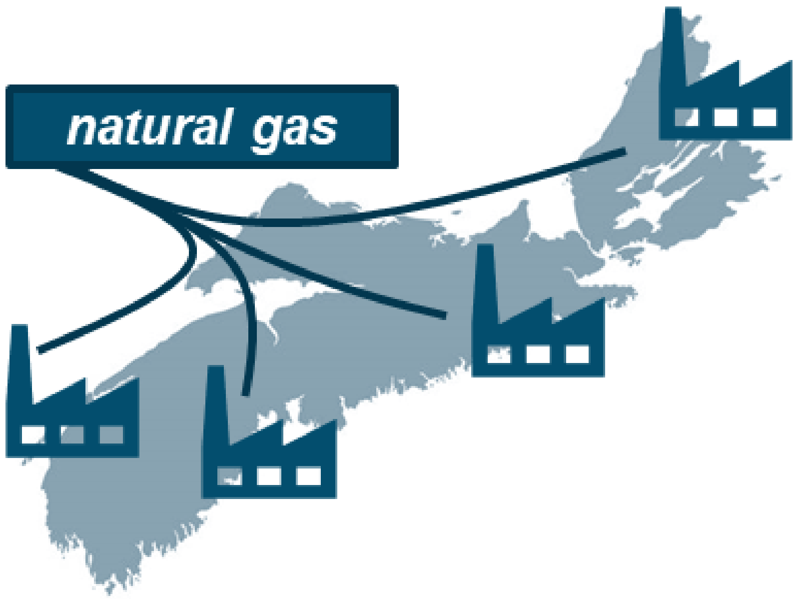
Transmission Lines

+ **No internal transmission constraints assumed within Nova Scotia**
+ **Maritime Link**
  - Day time capacity of 153 MW starting in 2020
  - Pole 1 transmission line
    - 250 MW
    - 96% availability
  - Pole 2 transmission line
    - 250 MW
    - 96% availability
  - Combined DAFOR of ML+LIL+Muskrat Falls = 2%
+ **Base Energy**
  - Muskrat Falls: 153 MW
  - 7 am – 11 pm



Fuel Supply

- **This analysis assumes any fuel supply constraints are represented in the de-rated adjusted forced outage rate (DAFOR) and are not correlated with one another**
  - To the extent that outages are correlated, this would increase the target PRM
- **Access to firm natural gas fuel supply during winter peak electricity events could be challenging to NSPI if new capacity is added which would further constrain gas pipeline import capacity**
- **Various options for firm fuel supply exist**
  - New pipeline capacity
  - On-site fuel storage
  - In-province gas storage
  - LNG import capability
- **More information will be coming on this topic as the IRP progresses**



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Results

NSPI 2020 System Reliability and PRM

Metric	Units	High Case	Low Case
Loss of Load Expectation (LOLE)	days/yr	0.19	0.04
Annual LOLP (%)	%	15.4%	3.0%
Loss of Load Hours (LOLH)	hrs/yr	1.29	0.016
Loss of Load Events (LOLEV)	events/yr	0.17	0.03
Expected Unserved Energy (EUE)	MWh/yr	49	7.6
Normalized EUE	% of annual load	0.0005%	0.00008%
1-in-2 Peak Load	MW	2,070	2,070
PRM Requirement	% of peak	21.0%	17.8%

+ **High Operating Reserve Requirement Case:** 100 MW operating reserve requirement in all hours, approximately 5% of NSPI's peak load
+ **Low Operating Reserve Requirement Case:** 33 MW operating reserve requirement in all hours, approximately 1.5% of NSPI's peak load
+ Operating reserves represent the quantity of reserves that must be maintained and which NSPI will shed load to maintain – these values are less than the typical operating reserves that are held by NSPI which can decrease in extreme grid conditions. Operating reserves are necessary to be able to quickly react to unexpected grid conditions that might otherwise result in significant grid problems if operating reserve are not available

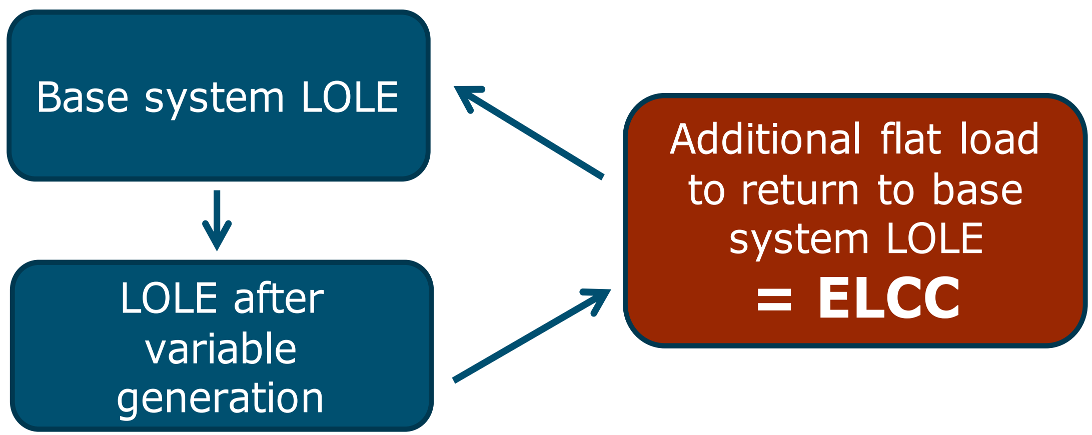
Load and Resource Balance

High Operating Reserve Requirement Case

Load			
Firm Peak Load Net of DSM (MW)	2,070		
Target Reliability Standard	0.1 days/year		
Target PRM	21.0%		
Total Requirement (MW)	**2,504**		
Resource	**Nameplate Capacity (MW)**	**Effective Capacity (MW)**	**Effective Capacity (%)**
Coal	1,081	1,081	100%
Oil	231	231	100%
Natural Gas/Heavy Fuel Oil	462	462	100%
Biomass/Biogas	76	76	100%
Run-of-River Hydro	162	154	95%
Wreck Cove Hydro	212	202	95%
Annapolis Tidal	19	2.3	12%
Wind	596	111	19%
Solar	1.7	0.08	5%
Maritime Link Base Energy Imports	153	151	98%
Total Supply (MW)	**2,994**	**2,470**	78%
Surplus/Deficit (MW)	**-38**		

Effective Load Carrying Capability (ELCC)

+ **ELCC measures the ability of dispatch-limited resources to contribute to planning reserve requirements while still maintaining an equivalent level of reliability**
  - ELCC is the quantity of “perfect capacity” that could be replaced or avoided with renewables, storage, or DR
  - A value of 50% means the addition of 100 MW of energy storage would displace the need for 50 MW of firm capacity without compromising reliability
  - ELCC is well-established as the most analytically rigorous method for calculating the capacity of dispatch-limited resources such as solar, wind, hydro, storage, and demand response



Effective Capacity of All Resources

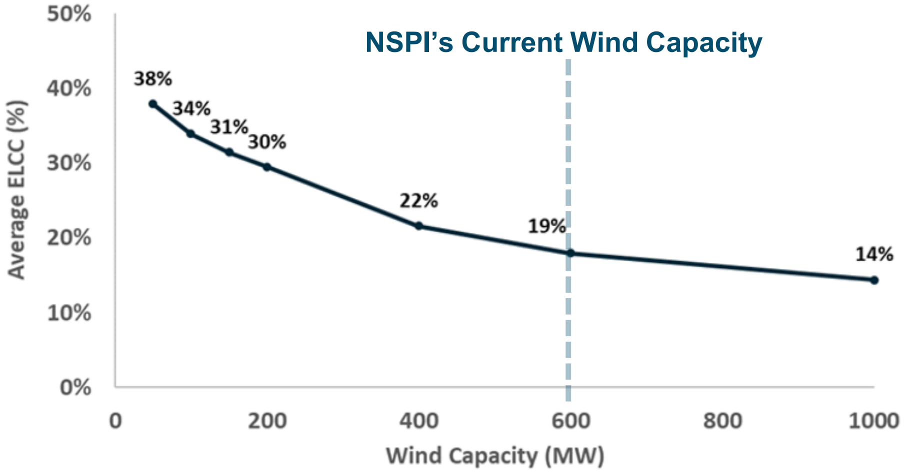
- Dispatchable resources are by convention generally counted at their nameplate capacity in PRM accounting
- Due to forced outages, and "ELCC" equivalency can be calculated for these resources to compare on equal basis with renewables as shown below

Resource	Nameplate Capacity (MW)	Effective Capacity (MW)	Effective Capacity (%)
Coal	1081	958	92%
Oil	231	191	78%
HFO/NG	462	376	75%
Biomass/Biogas	76	69	97%
Run-of-River Hydro	162	154	95%
Wreck Cove Hydro	212	201	95%
Annapolis Tidal	19	2.3	12%
Wind	596	113	19%
Solar	2	0.09	5%
Maritime Link Base Energy Imports	153	150	98%
Total	**2,994**	**2,215**	

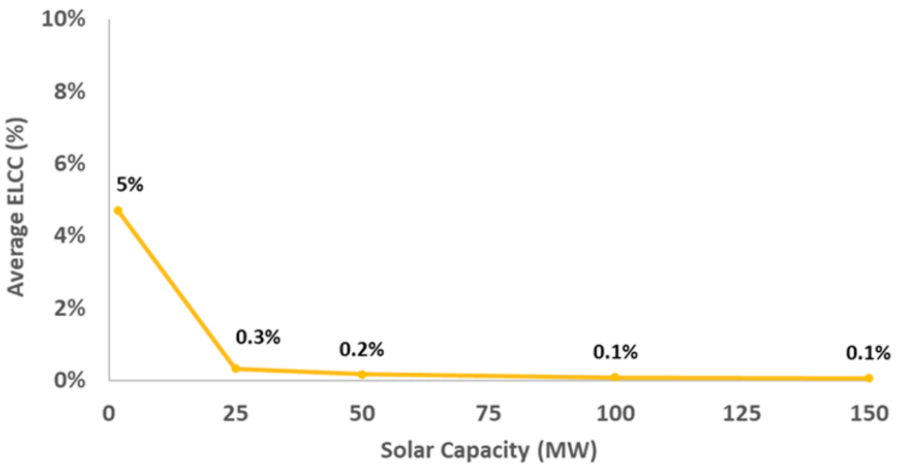
ELCC of Wind and Solar

+ **Both wind and solar exhibit declining ELCC as penetrations increase – a phenomenon seen across all geographies and all resources**

Wind ELCC



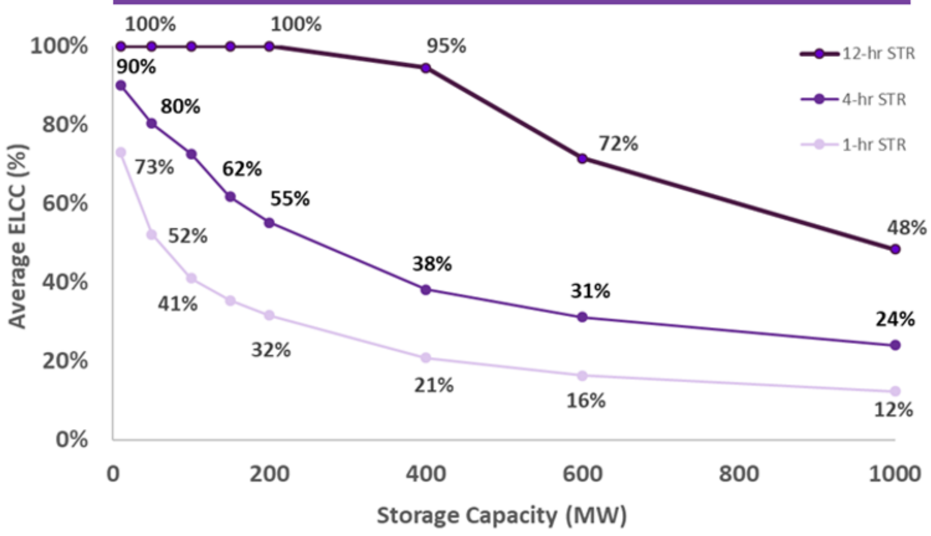
Solar ELCC



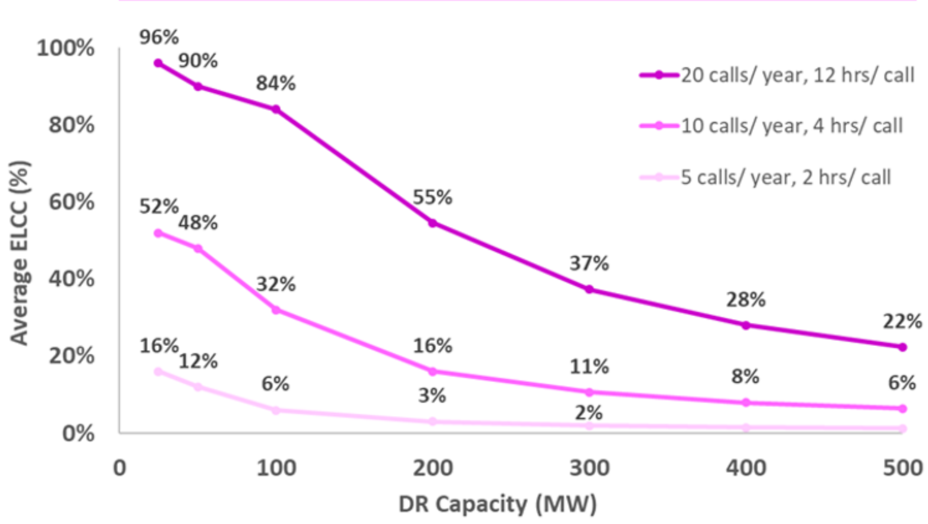
ELCC of Storage and Demand Response

- Energy storage and demand response (DR) also exhibit diminishing returns as penetration increases
- The demand response results are not meant to map directly to specific existing DR programs but rather inform system planners of the ELCC value that a DR program with similar attributes might provide

Storage ELCC

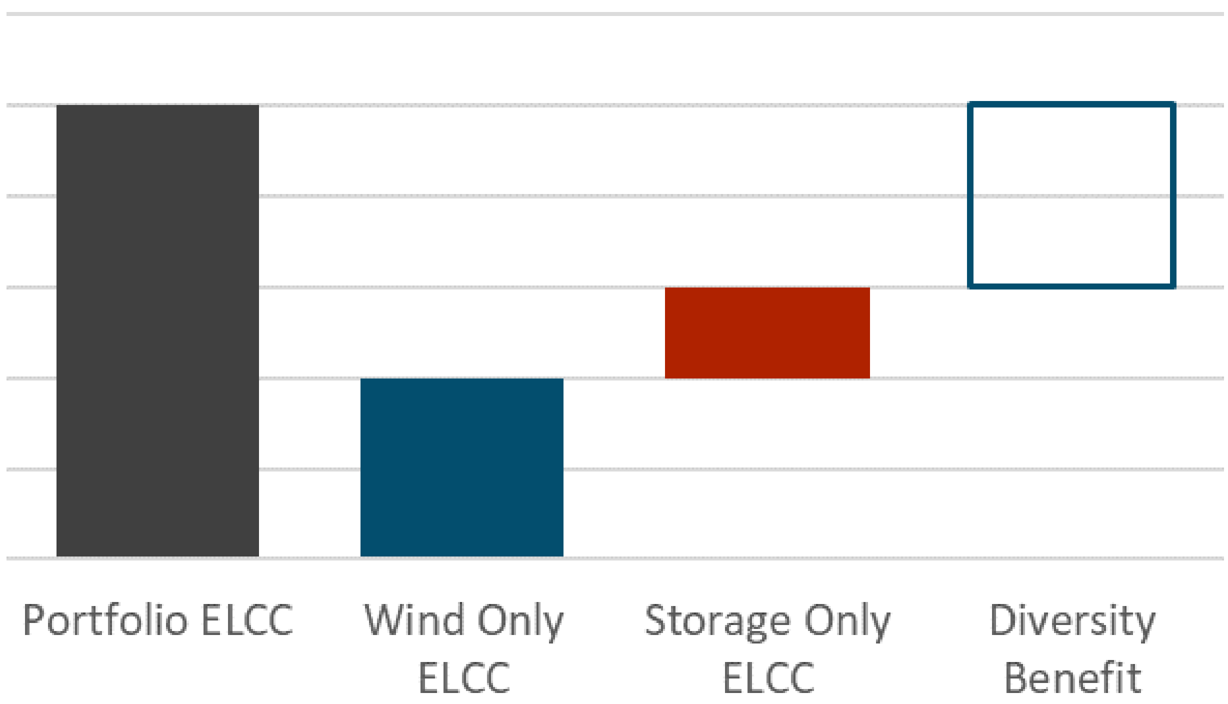


Demand Response ELCC



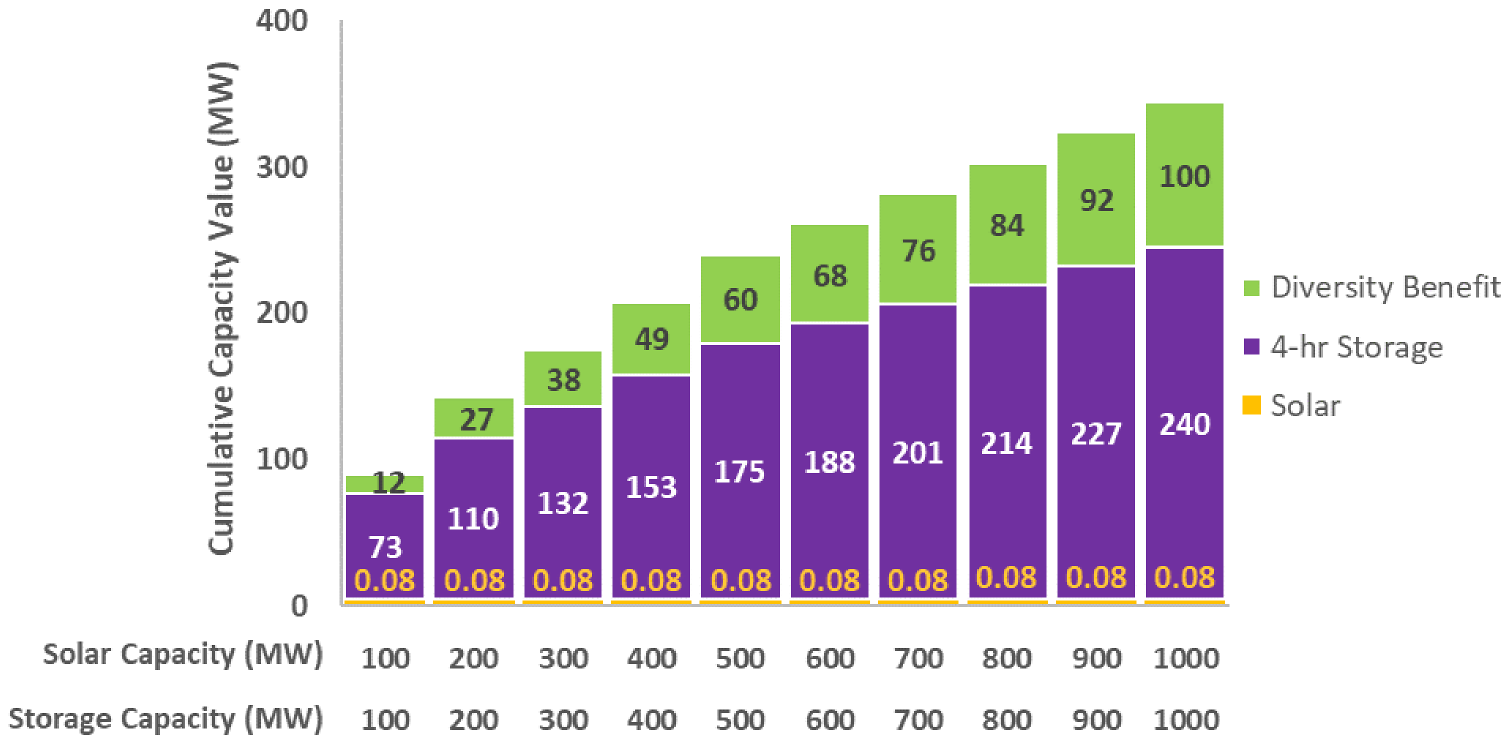
Portfolio ELCC & Diversity

+ **The ELCC of a portfolio of resources is often more than the sum of their parts – creating a diversity benefit that must be allocated between the resources**



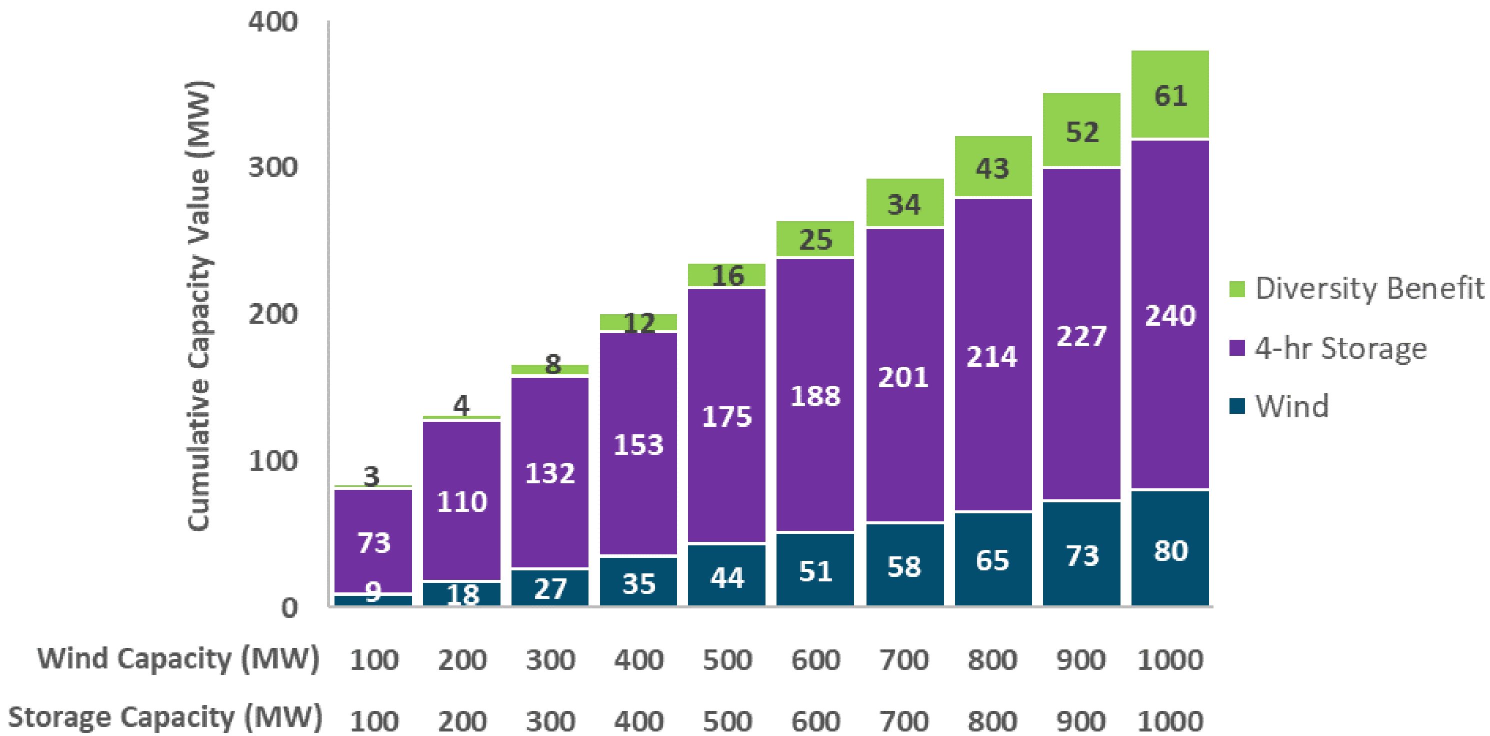
Diversity Benefit of Solar + Storage

- **Stand-alone solar provides negligible capacity value to the system due to low coincidence between generation and evening winter peak load**
- **Solar and storage pair well together due to the diurnal pattern of solar and the ability of storage to shift that energy to the evening peak**



Diversity Benefit of Wind + Storage

+ **Wind and solar also create a diversity benefit, but it is smaller than solar due to the potential for multiple days of low wind generation which depletes storage**



Conclusions

+ **NSPI requires a 17.8% - 21.0% PRM to maintain a 0.1 days/yr loss of load expectation (LOLE) target**
  - Dependent upon the specific portfolio
+ **Dispatch-limited resources such as wind, solar, storage, and demand response can contribute effective load carrying capability (ELCC) toward meeting the planning reserve margin requirement, but have diminishing returns as additional capacity is added to the system**

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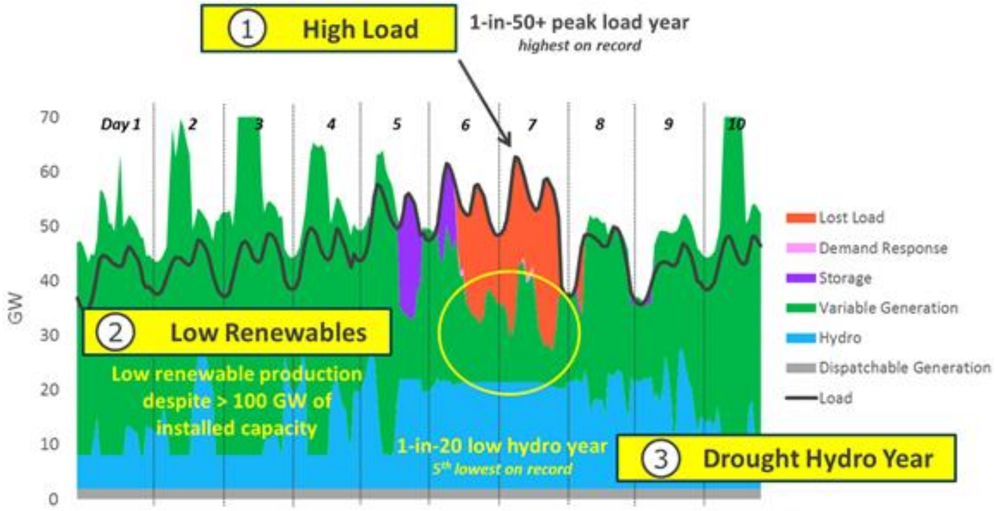
Appendix

Evaluating Reliability Metrics

- **Reliability metrics measure outages in terms of**
  - Frequency
  - Duration
  - Magnitude
- **Target reliability metrics are not standard across the industry and are often not rigorously justified**



- **1-day-in-10-year LOLE is often used but this metric does not capture the duration or magnitude of individual events**
- **E3 research has shown that for traditional and high-renewable systems with equivalent LOLE, the high-renewable systems tend to have more severe (higher magnitude) events**
  - This is due to variability in renewable resource availability
- **While LOLE is the most common reliability metric standard, E3 recommends that jurisdictions should investigate establishing alternative standards that more explicitly take economics into account**

https://www.nerc.com/comm/PC/Documents/2.d_Probabilistic_Adequacy_and_Measures_Report_Final.pdf

RECAP Model Overview

+ **Resource adequacy is a critical concern under high renewable and decarbonized systems**
  - Renewable energy availability depends on the weather
  - Storage and Demand Response availability depends on many factors
+ **RECAP evaluates adequacy through time-sequential simulations over thousands of years of plausible load, renewable, hydro, and stochastic forced outage conditions**
  - Captures thermal resource and transmission forced outages
  - Captures variable availability of renewables & correlations to load
  - Tracks hydro and storage state of charge

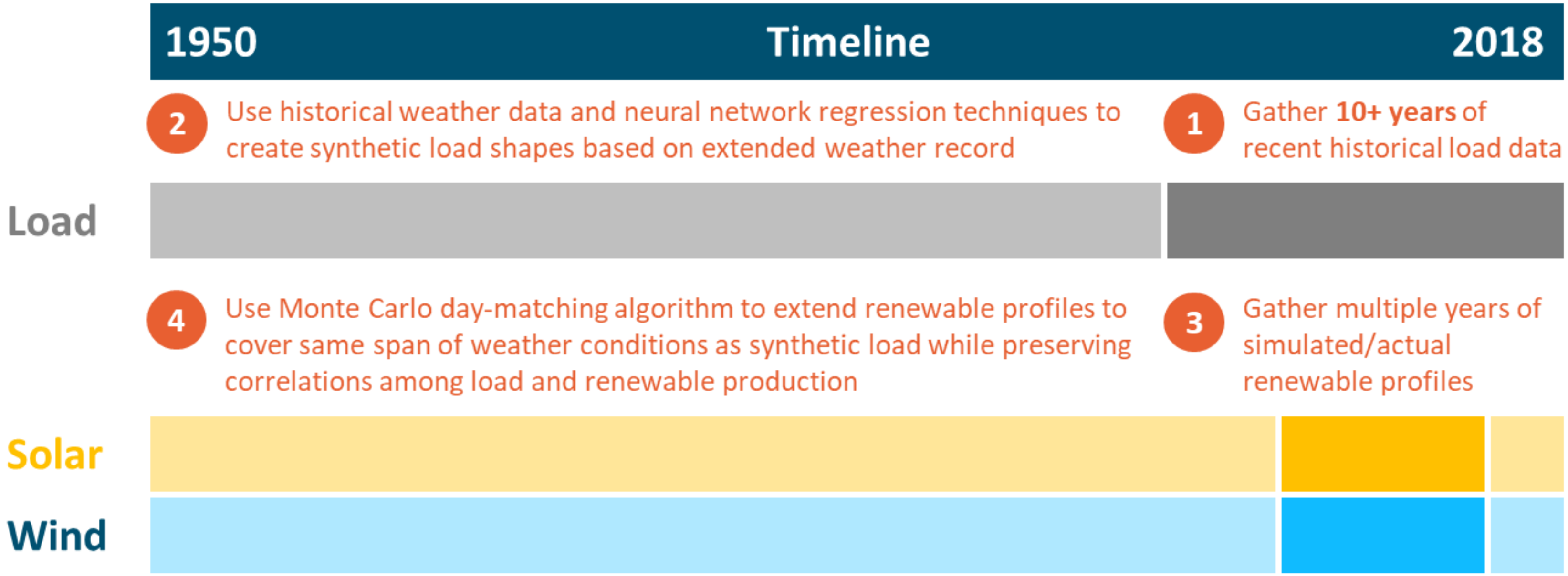
RECAP calculates reliability metrics for high renewable systems:

- **LOLP:** Loss of Load Probability
- **LOLE:** Loss of Load Expectation
- **EUE:** Expected Unserved Energy
- **ELCC:** Effective Load-Carrying Capability for hydro, wind, solar, storage and DR
- **PRM:** Planning Reserve Margin needed to meet specified LOLE

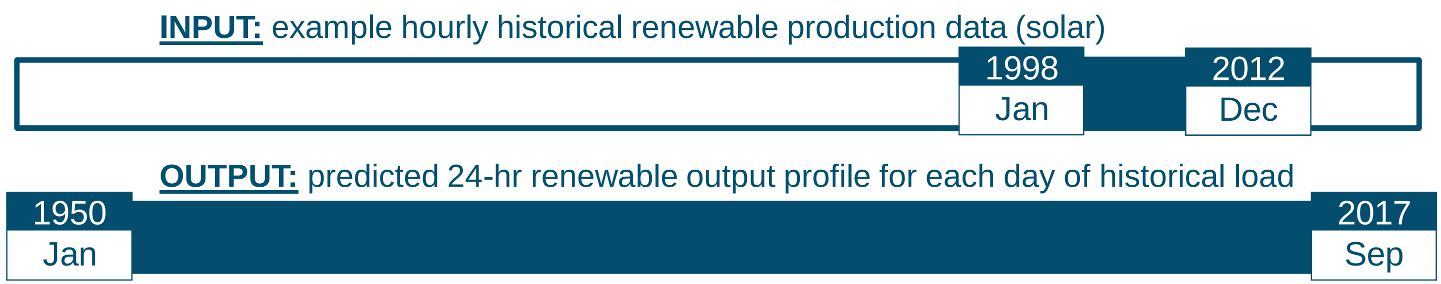
Information about E3's RECAP model can be found here: https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/

Developing Hourly Loads and Renewable Profiles

- Capturing a wide range of potential load, wind, and solar conditions while preserving the underlying relationships among them is crucial to performing a robust loss-of-load-probability analysis
- Raw data covering a sufficient range of conditions is often unavailable
- RECAP's process for extending profiles to cover a large range of years is shown below



Predicting Renewable Output

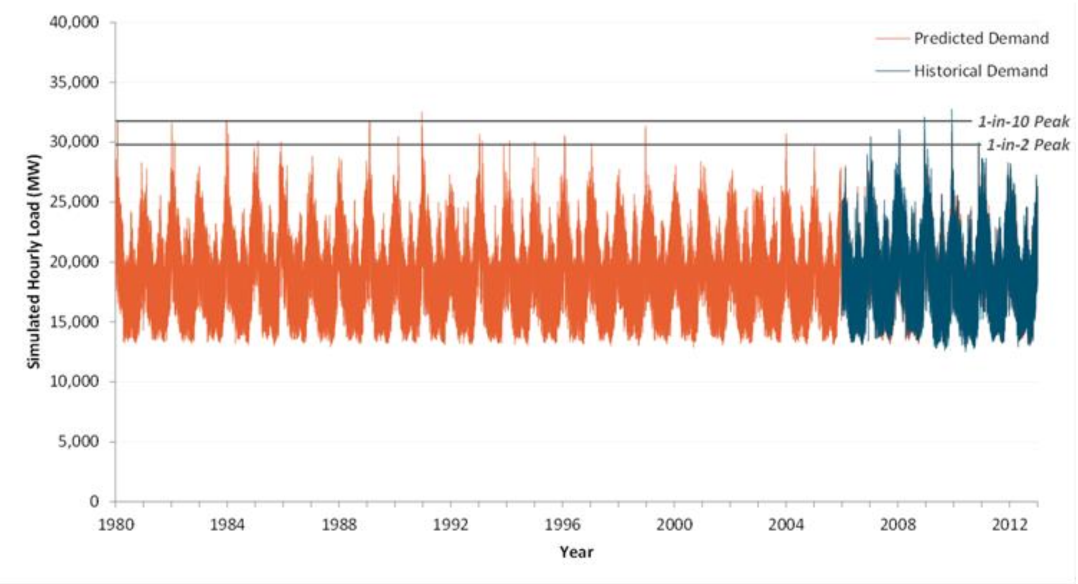


+ Renewable generation is uncertain, but its output is correlated with many factors

- Season
  - Eliminate all days in historical renewable production data not within +/- 15 calendar days of day trying to predict
- Load
  - High load days tend to have high solar output and can have mixed wind output
  - Calculate difference between load in day trying to predict and historical load in the renewable production data sample
- Previous day’s renewable generation
  - Captures effect of a multi-day heatwave or multi-day rainstorm
  - Calculate difference between previous day’s renewable generation and previous day’s renewable generation in renewable production data sample

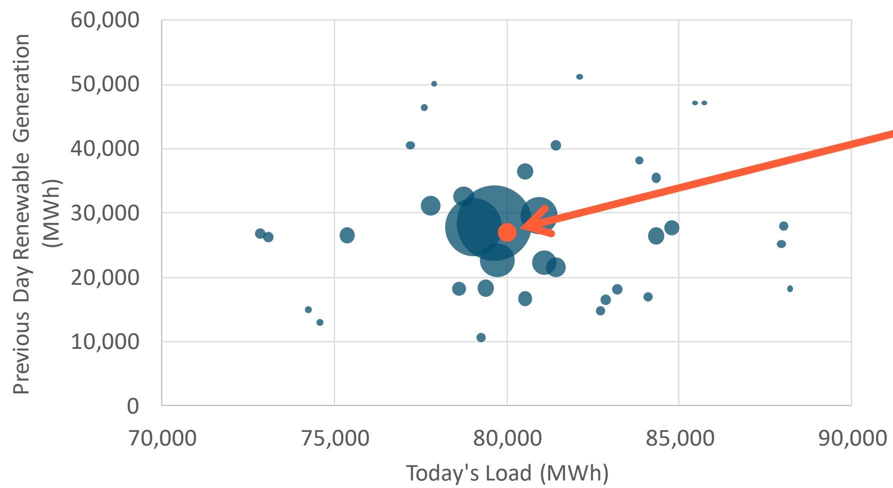
Backcasting Hourly Loads

- Developing a robust set of hourly load profiles that is representative of a broad distribution of possible weather conditions – particularly extreme events that are often correlated with higher risk of loss of load – is a challenge for reliability modelers
- E3 develops a neural network regression using actual hourly loads from recent historical years (5-10 years) and a longer record of key weather indicators (30-70 years)
- The result is a profile of hourly loads that represent how today's electric demands would behave under a wide range of plausible weather conditions



Predicting Renewable Output

- Each blue dot represents a day in the historical sample
- Size of the blue dot represents the probability that the model chooses that day



Aug 12, 1973	
Daily Load	80,000 MWh
Previous-Day Renewable Generation	27,000 MWh

Probability Function Choices

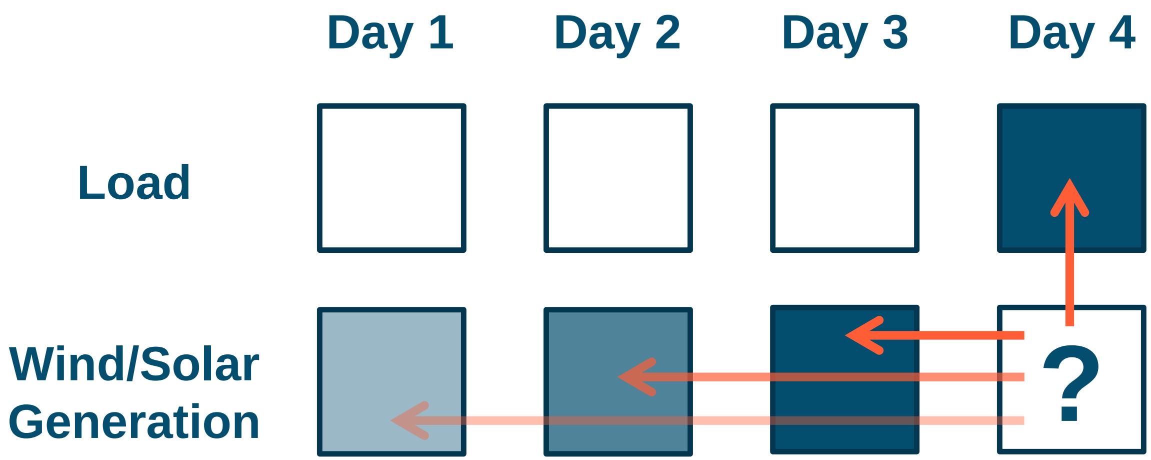
$\boxed{\text{Inverse distance}}$
Square inverse distance
Gaussian distance
Multivariate normal

Probability of sample i being selected $= \dfrac{\dfrac{1}{Distance_i}}{\sum_{j=1}^{n} \dfrac{1}{Distance_j}}$

Where $distance_i$ = $\text{abs}[\text{load}_{\text{Aug 12}} - \text{load}_i]/\text{stderr}_{\text{load}} + \text{abs}[\text{renew}_{\text{Aug 12}} - \text{renew}_i]/\text{stderr}_{\text{renew}}$

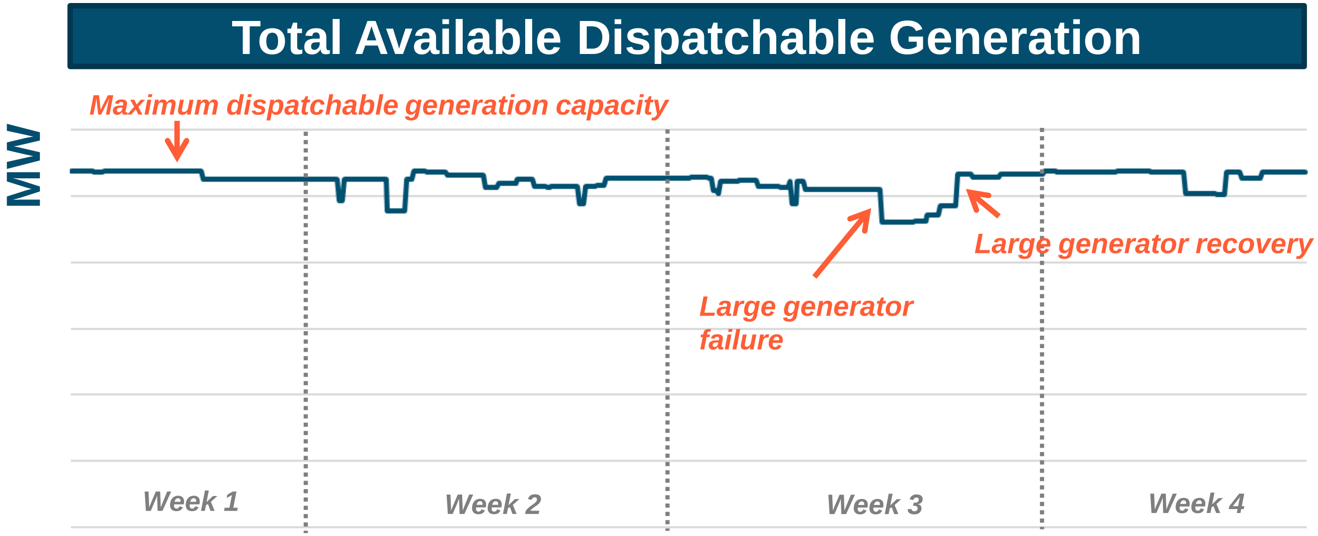
Synthesizing Hourly Wind/Solar Profiles

- To select a daily wind/solar profile, the model analyzes the load on the day as well as the previous 3+ days of wind/solar generation (with the most recent days being weighted highest)
- The model searches through the actual load and wind/solar historical record to find similar days and assigns each daily wind/solar profile a similarity rating to the day being predicted based on load and preceding days' wind/solar
- The model probabilistically selects a daily wind/solar profile through monte carlo analysis using similarity ratings as probability weights



Stochastic Outages

+ **Hourly dispatchable generator and transmission availability is calculated by stochastically introducing forced outages based on each generator's**
  - Forced outage rate (FOR)
  - Mean time to failure (MTTF)
  - Mean time to repair (MTTR)



Wind and Solar ELCC

Wind Capacity (MW)	ELCC (MW)	Average ELCC	Marginal ELCC
50	19	38%	38%
100	34	34%	30%
150	47	31%	27%
200	59	30%	24%
400	86	22%	14%
600	108	18%	11%
1,000	144	14%	9%
1,500	182	12%	8%
2,000	212	11%	6%
5,000	288	6%	3%

Solar Capacity (MW)	ELCC (MW)	Average ELCC	Marginal ELCC
1.7	0.08	4.7%	4.7%
25	0.08	0.3%	0.0%
50	0.08	0.2%	0.0%
100	0.08	0.1%	0.0%
150	0.08	0.1%	0.0%
200	0.08	0.0%	0.0%
400	0.08	0.0%	0.0%

1 and 2-hr Duration Storage ELCC

1-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	7	73%	73%
50	26	52%	47%
100	41	41%	30%
150	53	35%	24%
200	63	32%	21%
400	83	21%	10%
600	98	16%	8%
1,000	122	12%	6%

2-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	9	90%	90%
50	33	65%	59%
100	57	57%	48%
150	71	47%	28%
200	82	41%	22%
400	108	27%	13%
600	130	22%	11%
1,000	170	17%	10%

4 and 12-hr Duration Storage

4-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	9	90%	90%
50	40	80%	78%
100	73	73%	65%
150	93	62%	40%
200	110	55%	35%
400	153	38%	21%
600	187	31%	17%
1,000	240	24%	13%

12-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	10	100%	100%
50	50	100%	100%
100	100	100%	100%
150	150	100%	100%
200	200	100%	100%
400	378	95%	89%
600	429	72%	26%
1,000	484	48%	14%

Demand Response ELCC

DR Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
25	4	16%	16%
50	6	12%	8%
100	6	6%	0%
200	6	3%	0%
300	6	2%	0%
400	6	2%	0%
500	6	1%	0%

DR Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
25	13	52%	52%
50	24	48%	44%
100	32	32%	16%
200	32	16%	0%
300	32	11%	0%
400	32	8%	0%
500	32	6%	0%

Demand Response ELCC

DR Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
25	24	96%	96%
50	45	90%	84%
100	84	84%	78%
200	109	55%	25%
300	112	37%	3%
400	112	28%	0%
500	112	22%	0%

Solar + Storage ELCC

Solar Capacity (MW)	Storage Capacity (MW)	Solar Standalone ELCC (MW)	4-hr Storage Standalone ELCC (MW)	Solar + Storage ELCC (MW)	Diversity Benefit (MW)
100	100	0.1	73	85	12
200	200	0.1	110	138	27
300	300	0.1	132	170	38
400	400	0.1	153	203	49
500	500	0.1	175	235	60
600	600	0.1	188	256	68
700	700	0.1	201	277	76
800	800	0.1	214	298	84
900	900	0.1	227	319	92
1,000	1,000	0.1	240	340	100

Wind + Storage ELCC

Wind Capacity (MW)	Storage Capacity (MW)	Wind Standalone ELCC (MW)	4-hr Storage Standalone ELCC (MW)	Wind + Storage ELCC (MW)	Diversity Benefit (MW)
100	100	9	73	85	3
200	200	18	110	132	4
300	300	27	132	166	8
400	400	35	153	201	12
500	500	44	175	235	16
600	600	51	188	264	25
700	700	58	201	293	34
800	800	65	214	323	43
900	900	73	227	352	52
1,000	1,000	80	240	381	61

Nova Scotia

Reliability Metric(s) and Standard

- LOLE: 0.1 days/year
  - NPCC Regional Reliability Directory #1

Reserve Margin

- 20% planning reserve margin to meet LOLE standard

Loss of Load Modeling

- Probabilistic Assessment of System Adequacy (PASA) module of PLEXOS

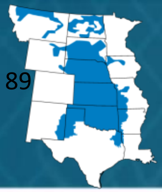
Reserve Margin Accounting – Resource

- Net capability for dispatchable resources
- ELCC for renewable resources

Reserve Margin Accounting – Load

- Median peak load

SPP



Reliability Metric(s) and Standard

- LOLE: 0.1 days/year

Reserve Margin

- PRM is derived to meet 0.1 LOLE
- Resulting non-coincident PRM is 12.0% for general entities and 9.8% for hydro-based entities
- Equivalent coincident PRM is 16.0%
- PRM updated every 2 years
- Each Load Responsibly Entity must procure capacity resources

Loss of Load Modeling

- GridView and SERVM

Reserve Margin Accounting – Resource

- Net capability for dispatchable resources
- Wind/solar capacity credit counted using heuristic top load hour methodology

Reserve Margin Accounting – Load

- Peak load under median median weather conditions
- Behind-the-meter generation subtracted from gross load
- Operating reserves not included but are on the list for future consideration

MISO

Reliability Metric(s) and Standard

- LOLE: 0.1 days/year

Reserve Margin

- PRM is derived to meet 0.1 LOLE
- UCAP PRM is 7.9% of each LSE's CP
- ICAP PRM is 16.8% of MISO CP
- PRM updated annually

Loss of Load Modeling

- SERVM

Reserve Margin Accounting – Resource

- UCAP: Capacity de-rated for forced outages
- ICAP: Installed capacity
- Renewable credit established by ELCC study
  - Wind: 15.2%
  - Solar: 50%

Reserve Margin Accounting – Load

- Median forecasted peak net internal demand
- Operating reserves are not included

Reliability Metric(s) and Standard

- No explicit standard

Reserve Margin

- Recent study concluded:
  - Market equilibrium reserve margin: 10.25%
  - Economically optimal reserve margin: 9%
    - VOLL: $9,000/MWh
- "Purely information" target PRM of 13.75% (acknowledges higher than economically optimal)
  - Achieves 0.1 events/yr
- Reserve margin is ultimately determined by suppliers' costs and willingness to invest based on market prices

Reserve Margin Accounting – Resource

- Dispatchable units are counted by seasonal net sustained capacity
- Hydro is counted by peak seasonal capacity contribution
- Renewable units are de-rated by seasonal peak-average capacity contribution methodology
  - Non-coastal wind: 14%
  - Coastal wind: 59%
  - Solar: 75%

Reserve Margin Accounting – Load

- Median peak load
- Operating reserves added to load

Loss of Load Modeling

- SERVM

Reliability Metric(s) and Standard

- LOLE: 0.1 days/year

Reserve Margin

- Minimum Installed Reserve Margin (IRM) requirement is set to meet 0.1 LOLE
- Minimum IRM is 16.8% in 2019
- Demand curve approach is utilized such that achieved IRM exceeds minimum IRM in most cases
  - Linear slope between minimum IRM (1.5x CONE) and all capacity offered
  - 27% achieved in 2018
- Updated annually
- Local capacity requirements (LCRs) existing for different zones
- Achieved IRM is based on demand curve bidding process

Reserve Margin Accounting – Resource

- IRM based on installed nameplate capacity
  - UCAP requirement is based on capacity de-rated for forced outages but requirement is lower than IRM
- Renewables are de-rated using heuristics for winter and summer

Reserve Margin Accounting – Load

- Peak load is predicted from normal weather conditions simulated over 20 historical weather years (50/50 peak)
- Operating reserves are not included

Loss of Load Modeling

- GE-MARS

Reliability Metric(s) and Standard

- LOLE: Demand Curve
  - 0.2 days/year
  - 0.1 days/year
  - 0.01 days/year

Reserve Margin

- Updated annually
- Demand curve reserve margin points for 2019
  - 13.1% (0.2 LOLE)
  - 16.8% (0.1 LOLE)
  - 26.1% (0.01 LOLE)

Loss of Load Modeling

- GE-Mars

Reserve Margin Accounting – Resource

- Dispatchable resources counted at installed nameplate capacity
- Renewables qualified capacity is performance based, counted by the resource's median output during "reliability hours" over 5 years
- Reliance on the interties is counted

Reserve Margin Accounting – Load

- Peak load is predicted from median (50/50) weather conditions
- Energy efficiency is considered as passive demand resource and not embedded in load
- Behind-the-meter PV is counted as a resource
- Operating reserves are included

PJM

Reliability Metric(s) and Standard

- LOLE: 0.1 events/year
  - BAL-502-RFC-02

Reserve Margin

- Installed Reserve Margin (IRM) is set to meet 0.1 LOLE
- IRM is used as an input into capacity auction demand curve
  - The recommended IRM for 2019/20 period is 16.0%
    - 1.5x Net-CONE @ IRM – 0.2%
    - 0.75x Net-CONE @ IRM + 2.9%
    - 0x Net-CONE @ IRM + 8.8%
- Updated annually
- Locational Deliverability Areas (LDAs) are modeled in addition to IRM

Reserve Margin Accounting – Resource

- Dispatchable units are counted by summer net dependable capacity in IRM
- Renewables' ICAP calculated using heuristic capacity credit (similar to ELCC)

Reserve Margin Accounting – Load

- Median peak load
- Behind-the-meter PV is embedded into load

Loss of Load Modeling

- Probabilistic Reliability Index Study Model (PRISM)
  - PRM internal tool

Reliability Metric(s) and Standard

- No explicit reliability standard

Reserve Margin

- Resource Adequacy program sets the Planning Reserve Margin (PRM) to at 15% on a monthly basis
- LSEs are responsible for procuring RA
- RA program contains system, local, and flexible RA requirements

Loss of Load Modeling

- RECAP used to calculate DER values
- SERVM model used to calculate renewable ELCCs

Reserve Margin Accounting – Resource

- Monthly Net Qualifying Capacity (NQC) to calculate total available capacity
- NQC of renewable resources is counted by ELCC
- LSEs can use imports to meet the RA requirements

Reserve Margin Accounting – Load

- Peak load is 1-in-2 weather normalized
- Behind-the-meter PV and energy efficiency are embedded in peak demand
- Operating reserves are not included

Reliability Metric(s) and Standard

- EUE: 800 MWh/year; NormEUE: 0.0014%

Reserve Margin

- Publishes quarterly reports monitoring the existing and forecasted reliability of the system
- If the forecasted EUE drops below the threshold metric, the AESO can take actions to bridge the supply gap
- 2017 reserve margin
  - 34% w/o intertie
  - 44% w/ intertie
- *Currently in process of developing a capacity market*

Reserve Margin Accounting – Resource

- N/A

Reserve Margin Accounting – Load

- N/A

Loss of Load Modeling

- SERVM

Florida

Reliability Metric(s) and Standard

- LOLE: 0.1 days/year

Reserve Margin

- Minimum reserve margin planning criterion of 15% in addition to LOLP threshold
- Analysis report published every other year
- FRCC calculates both generation-only reserve margin which does not include DSM and total reserve margin

Loss of Load Modeling

- Internal probabilistic modelling

Reserve Margin Accounting – Resource

- Installed capacity

Reserve Margin Accounting – Load

- Peak load is based on median weather conditions
- Operating reserves are not included

Reliability Metric(s) and Standard

- No explicit planning standard but calculates multiple metrics

Reserve Margin

- Selected a PRM of 13% in 2017 IRP
- Updated every 2 years
- Considers reliability, cost, and risk in determining target PRM
  - Tests system reliability and production cost in 10-year planning horizon given the PRM from 11% to 20%

Loss of Load Modeling

- Internal Planning and Risk (PaR) model

Reserve Margin Accounting – Resource

- Thermal units are counted at maximum dependable capacity at the time of system summer and winter peak
- Hydro is counted by the maximum capacity that is sustainable for one hour at the time of system summer peak
- Variable renewables (solar and wind) are de-rated by the peak capacity contribution among hours with the highest loss-of-load probability for east BAA and west BAA separately
- DR (Class 1 DSM) is counted as nameplate capacity

Reserve Margin Accounting – Load

- Peak load in the base case is based on normal weather year (1-in-2) from 20 weather years period
- Operating reserves are included
- Class 2 demand side management (DSM) resources such as energy efficiency, are embedded in load

Australia

Reliability Metric(s) and Standard

- Expected Unserved Energy (EUE): 0.002% of total energy demand
  - Standard is set based on the economically optimal value, with recognition of the shortcomings of the metric (doesn't account for length of outages, etc.)

Reserve Margin

- No explicit reserve margin requirement
- Australian Energy Market Operator forecasts EUE and can intervene in the market by procuring additional generator capability if necessary

Reserve Margin Accounting – Resource

- N/A

Reserve Margin Accounting – Load

- N/A

Loss of Load Modeling

- Internal modeling

Great Britain

Reliability Metric(s) and Standard

- LOLH: 3 hours/year
  - National Grid estimated LOLE during 2017/2018 winter is 0.001 hours/year
- Standard is set based on economic optimum

Reserve Margin

- No required standard, but de-rated capacity margin is monitored
  - De-rated for forced outages
- Modeled target de-rated margin in 2021 = 5%
- Achieved de-rated margin in 2018 = 12%

Reserve Margin Accounting – Resource

- Generators de-rated to account for availability for each technology (e.g. CCGT = 85%) of nameplate

Reserve Margin Accounting – Load

- Median winter peak

Loss of Load Modeling

- Internal modeling

The Republic of Ireland

Reliability Metric(s) and Standard

- LOLE: 8 hours/year
- Standard is set based on economic optimum

Reserve Margin Accounting – Resource

- Dispatchable units are de-rated for FOR in the capacity requirement and capacity market

Reserve Margin Accounting – Load

- N/A

Loss of Load Modeling

- Internal modeling

Reserve Margin

- LOLE standard is used to determine a MW capacity requirement
- The capacity requirement is used to determine capacity payments to generators
  - Net-CONE * Capacity Requirement determines total capacity payments which are divided between all generators
  - Generators paid based on de-rated capacity for FOR
  - Renewable units are subject to de-rating factors (i.e., Wind: 0.103; Solar PV: 0.055)

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Energy+Environmental Economics

Thank You

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SUPPLY OPTIONS STUDY:
OVERVIEW & DISCUSSION

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{E3 SLIDES (ATTACHMENT 18)}

RENEWABLES STABILITY STUDY:
OVERVIEW & DISCUSSION

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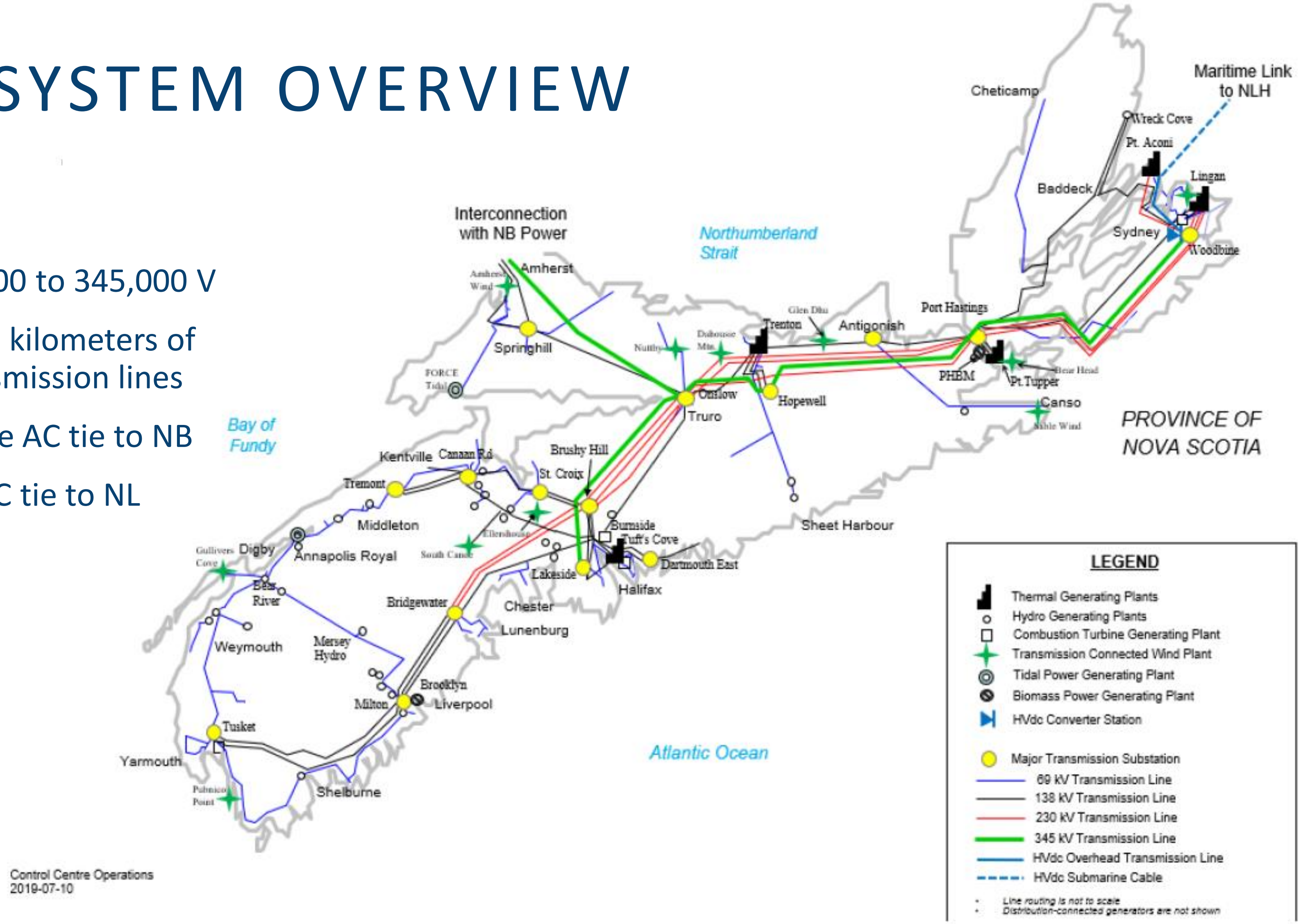
SYSTEM OVERVIEW

- 69,000 to 345,000 V
- 5200 kilometers of transmission lines
- Single AC tie to NB
- HVDC tie to NL



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STUDY BACKGROUND & OBJECTIVES

Stability Study for Renewables Integration (SSRI)

Power System Consultants (PSC) were contracted by NS Power to complete a System Stability Study associated with additional levels of Renewable Energy Integration.

The primary objective, to assess the integration of increased levels of renewable generation, was achieved by:

- ✓ Determining if 600MW is the limit with the existing Nova Scotia system
- ✓ Determining how much additional renewable energy can be accommodated with a second 345kv transmission tie to New Brunswick
- ✓ Recommending alternative system upgrades (i.e. synchronous generators, large scale batteries, etc.) that could allow increased levels of renewables
- ✓ Comparing experiences from other jurisdictions, such as Southern Australia and Ireland, for possible learnings for Nova Scotia

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STUDY APPROACH

SCENARIOS	Scenarios chosen for the study represent the system stability boundaries of the most potentially stressed conditions and the most significant contingencies.
MODELING	Transient stability simulations were executed to: • Assess each set of contingencies with 600MW of inverter based generation with the existing NS system configuration • Confirm additional levels of inverter based generation that could be installed with a second tie to New Brunswick in service • Calculate short circuit ratios • Assess potential renewable enabling solutions using large scale batteries and synchronous generators
ANALYSIS	PSC's international experience with South Australia and Ireland was reviewed for similarities and potential opportunities for Nova Scotia future planning. Regulation reserve using historical wind generation profiles was calculated for additional levels of renewable generation.

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LEARNINGS FROM OTHER JURISDICTIONS

South Australia experienced rapid growth in renewable generation. Low short circuit levels (system inertia) is a significant problem due to a large geographic area with long transmission lines between wind generation clustered remotely from synchronous machines.

- In 2016, South Australia experienced a state-wide blackout due to unforeseen sustained reduction of wind generators caused by transmission interconnector interruptions during an extreme weather event
- 850,000 customers lost supply; 90% restored in 8 hours, remainder within approximately 2 weeks

Load shedding is used in both the South Australia and Irish systems but not relied upon for mitigating the effects of planning contingencies.

Both South Australia and Ireland have introduced grid code changes, enhanced protection changes, and additional transmission infrastructure and dynamic compensation to accommodate increased levels of renewable generation.

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PRIMARY OBSERVATIONS & CONCLUSIONS

KEY FINDINGS FOR IRP SCENARIOS

- The existing NS system can remain stable with 600MW of inverter based renewable generation as long as NS maintains a minimum of three thermal units (or an equivalent short circuit level) on line.

- Up to 1000MW of inverter based renewable generation may be installed in NS with a second tie to New Brunswick in place.
  - The loss of the tie to New Brunswick is the most significant contingency impacting system stability and associated planning and operational actions.

  - Other renewable enabling technologies such as large scale batteries combined with synchronous condensers can provide a technical solution to increasing levels of inverter based generation but do not eliminate the reliability implications associated with loss of the existing AC tie.

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PRIMARY OBSERVATIONS & CONCLUSIONS

KEY FINDINGS FOR FURTHER STUDY & OPERATIONS

- The second tie likely eliminates the primary rationale for the minimum online thermal units but consideration must be given to other services provided by online thermal units such as tie balancing, load following, and local short circuit current and voltage control.
- Revision of grid codes (interconnection requirements) has been heavily relied upon in other jurisdictions to assist with system stability challenges.
- Total aggregate online inertia may provide a more general way of quantifying the minimum number of on line thermal unit requirement, however, expanded study would be required to further define this for Nova Scotia.
- Increased levels of inverter based generation is known to introduce potential power quality issues not within the scope of this study. Further study is required to fully understand the operational impact on the NS system.

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STUDY RECOMMENDATIONS

- Further study is required to establish system security levels, with expanded system conditions and scenarios, to confirm an operable renewable generation limit beyond 600MW.
  - The defined topology should include the second tie as a starting position to establish maximum renewable generation with minimum system reinforcement.
- Expand the existing study with broader system dispatch scenarios and establish requirements in terms of operational and reliability support.
- Perform enhanced studies in PSCAD software to refine technical requirements.
- Establish how the requirements could be met via service provision or grid code changes.
- Commission parallel studies to investigate other potential technical and operational limitations such as power quality.

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PRELIMINARY DR PROGRAM ASSUMPTIONS

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DR PROGRAM ASSUMPTIONS: INTRODUCTION

- NS Power has developed draft assumptions for three specific DR programs for discussion.
- Efficiency One (E1) has developed information on DR programs as part of its DSM Potential Study.
- The DR program assumptions are meant to be viewed as potential details of a few specific programs within the larger scope of DR considered by E1.
- NSP will continue to discuss with E1 and stakeholders to define the DR programs to be assessed in the Assumptions Development and Modeling phases of the IRP.

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SUMMARY OF PROPOSED DR PROGRAM ASSUMPTIONS

Device	Program	Peak shaving potential (kW/device)	Customer Incentive[1]	Participation Scenario (in year 25)	NSP Total Program Costs (25 year)
Water Heater	Controller installed on customer WH and used during peak shifting events	0.5	$25 enrollment, $25/yr when compliant to program criteria	Cumulative 50,779 participants (10% of market), 27 MW peak shaving potential	$1.49M/MW
EV Supply Equipment	Customer owned and installed EVSE with peak shifting participation incentives	0.7	$150 enrollment, $50/yr when compliant to program criteria	Cumulative 89,704 participants (70% of market), 63 MW peak shaving potential	$1.19M/MW
Residential Battery	Customer contribution comparable to diesel generator installation, utility control for up to defined number of system peak events	2.5	$2500 customer contribution, Balance of battery cost covered by NSP and funding where available	Cumulative 4,000 participants, 6.25 MW peak shaving potential	$8M/MW

[1] Customer behaviour-based peak shifting also through residential time of use, commercial time of use, and critical peak pricing rates.

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NEXT STEPS

NEXT STEPS

- We are soliciting feedback on the Pre-IRP Deliverables now, to allow time for revision and iteration prior to Assumptions Development phase.
- Next step will be formal kick-off of IRP with draft Terms of Reference
- Discussion/Addressing Questions: One-on-one or broader meetings to address further questions/feedback are available by request.
- Stakeholder Feedback:
  - While IRP kickoff begins, NSP welcomes written feedback on these materials for consideration.
  - We will use feedback to inform any revision/iteration on this work for Assumptions Development (or to influence Scenario Development that may capture input).

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PRE IRP DELIVERABLES: SECONDARY SESSION

AUGUST 27, 2019

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TODAY'S AGENDA

1. Continue discussion on pre-IRP deliverables:

I. **STABILITY STUDY FOR RENEWABLES INTEGRATION**

II. **SUSTAINING CAPITAL FORECAST**

III. **DEMAND RESPONSE PROGRAM ASSUMPTIONS**

2. Discuss Next Steps

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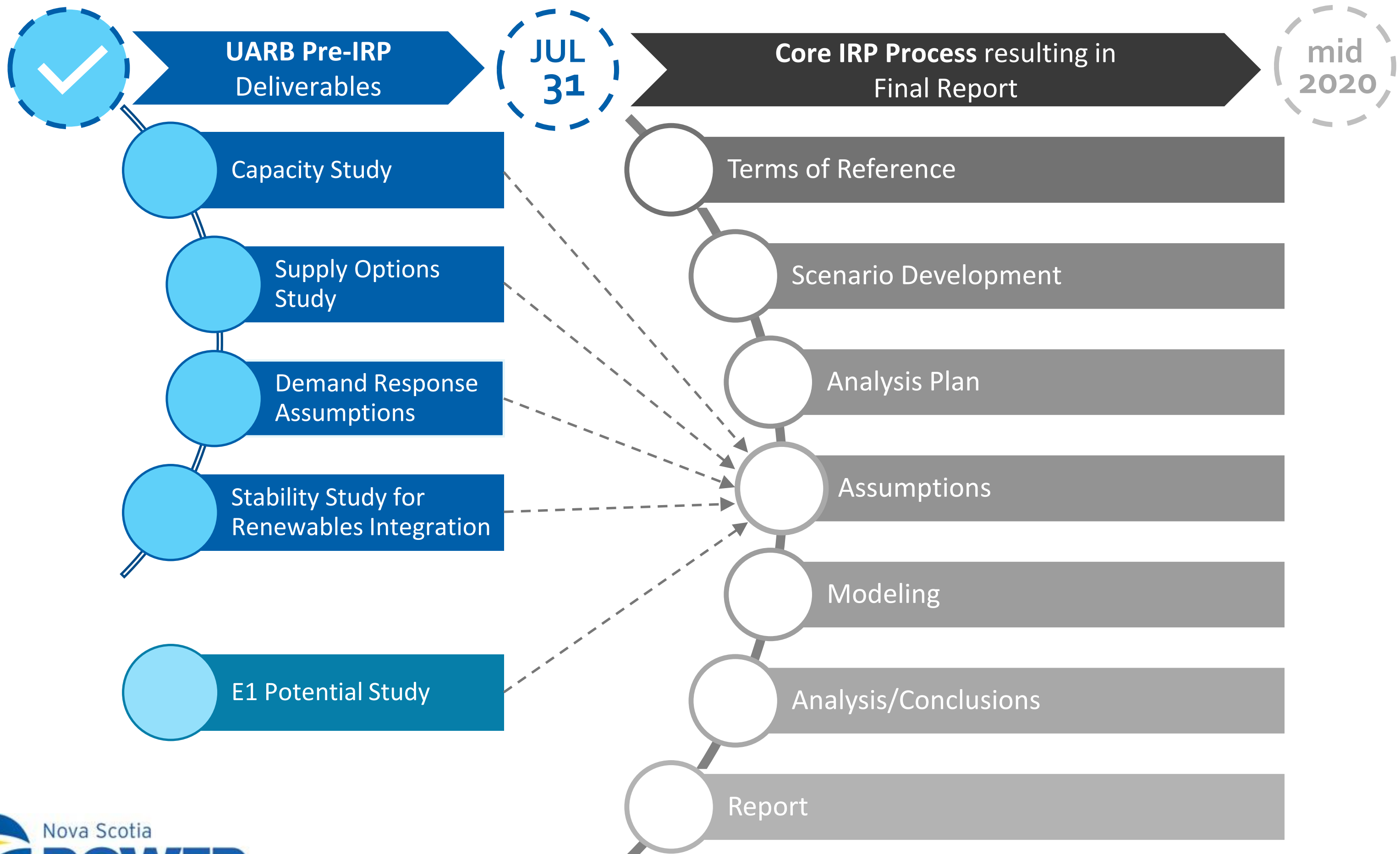
IRP PROCESS OVERVIEW



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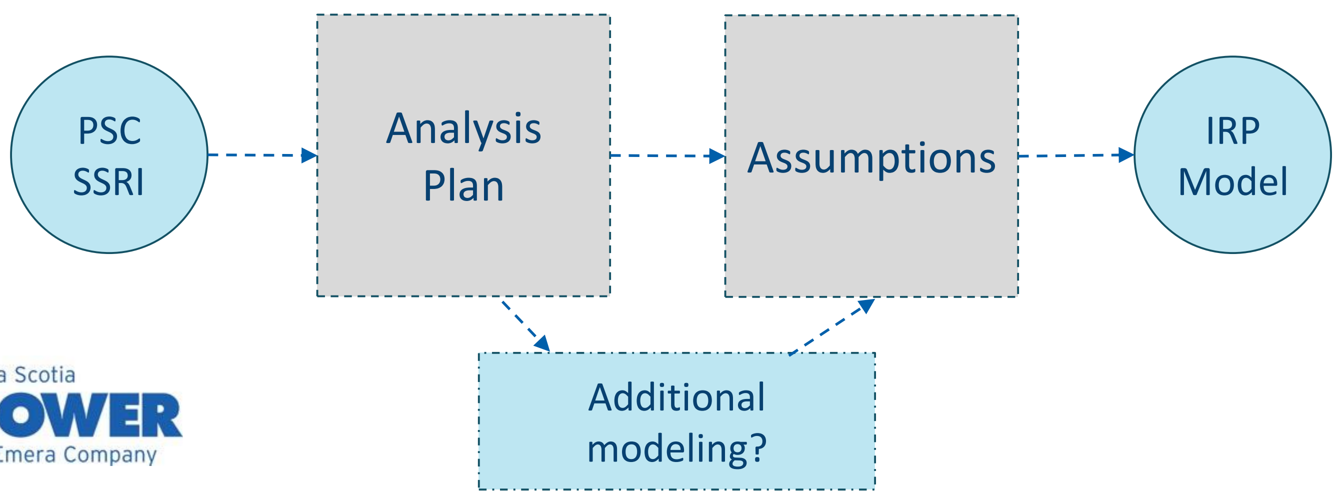
SSRI

STABILITY STUDY FOR RENEWABLES INTEGRATION

Context: How we will use the SSRI in the IRP

- NSP and our consultants are working to develop, as part of the IRP Analysis Plan, a methodology for estimating integration costs of additional wind based on stability issues that arise at higher penetrations (e.g. deficit in specific essential grid services) and the potential available solutions to solve the issues (this could involve additional PSSE model runs as required).
- Based on the SSRI as well as the methodology discussed above, we will define specific increments of wind, both up to and beyond 1000 MW, with interconnection requirements/costs to be brought forward to IRP stakeholders for review in the Analysis Plan and Draft Assumptions Phases.



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SSRI: QUESTION & ANSWER

- Why did the Stability Study for Renewables Integration (SSRI) stop at 1000 MW of wind in Nova Scotia?
- How is the Maritime Link taken into account in the study?
- Are the challenges associated with additional inverter-based generation dependant upon the resource type? Would the results have been the same if solar was added instead of wind?
- How were the study cases selected?
- Are the results sensitive to the location of the conventional resources online, and/or the location of the incremental wind?

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SSRI: QUESTION & ANSWER

- In cases with an additional New Brunswick tieline, does the additional tie change the level of MW import/export from/to New Brunswick?

- Re: Modifications to Case 01 (page 39 – 40): would this still be considered a “Light Load” case? Were any other load levels between 678 MW and 893 MW tested?

- In Case 04 with additional tieline, were the same mitigation measures implemented as described in the Base Case (additional thermal unit, shunts switched off)?

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SUSTAINING CAPITAL FORECAST

OVERVIEW

- The Pre-IRP Work provided preliminary high level cost projections for the existing supply side assets on the NS Power system.
- NS Power anticipates the Modeling Plan and Assumptions will include scenarios and/or sensitivities around these assumptions.
- Further detailed unit cost and operating assumptions will be provided in the Assumptions Development phase prior to modeling.
- The team will provide current updates to these parameters during the Assumptions Development phase of the IRP.

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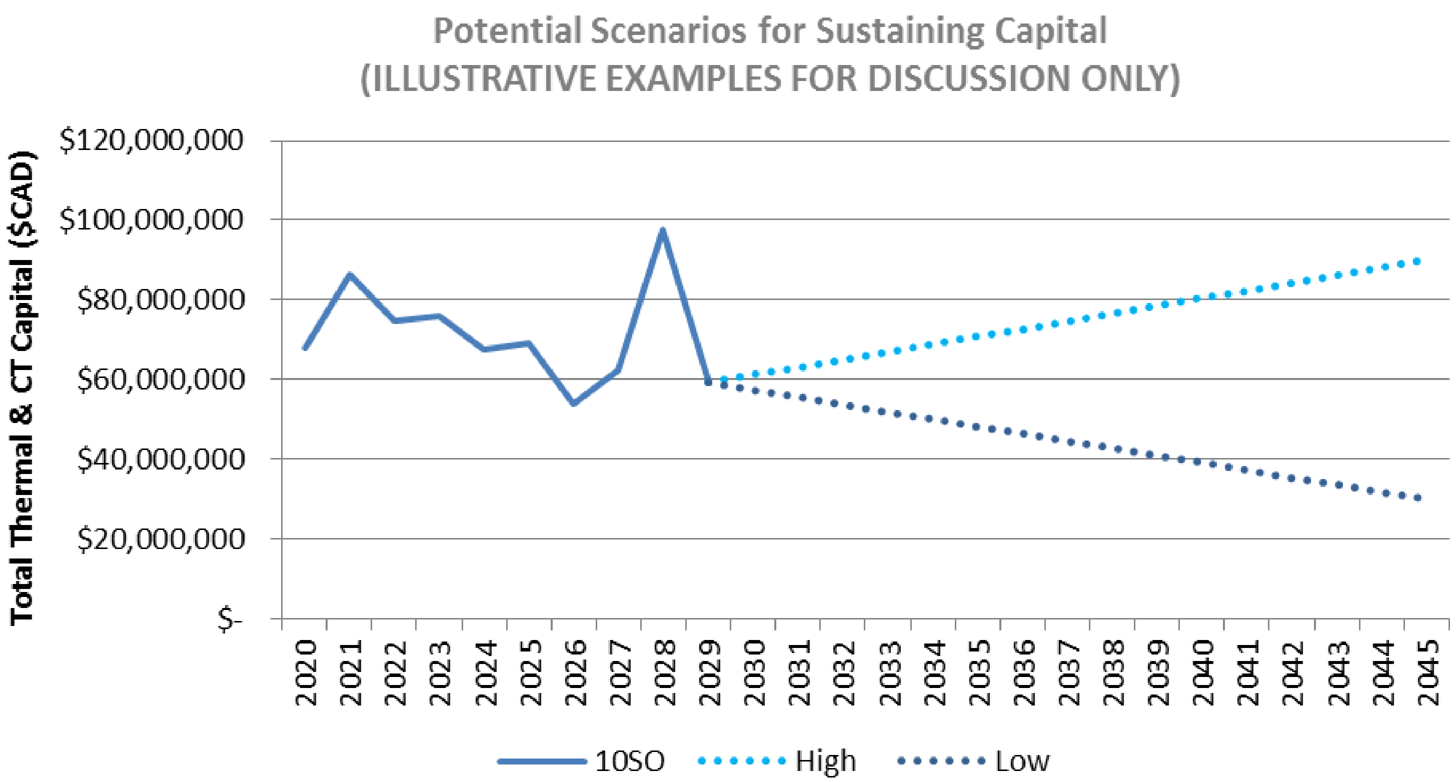
SUSTAINING CAPITAL FORECAST: BACKGROUND

- The sustaining capital forecast is developed based upon the expected utilization of the assets. The most recent cost forecast is from the 2019 10 Year System Outlook Report.

- NS Power conducted a Hydro Asset Study to estimate the costs of sustaining and decommissioning small hydro assets on the NS system. These costs, with updates as applicable, will be used as the cost assumptions for existing hydro units.

- Scenarios for sustaining capital (for example, different utilization factors driving different investment profiles) around sustaining capital, particularly in the longer term where uncertainty is increased, will be developed in collaboration with stakeholders through the Modeling Plan and Assumptions Development phases.

SUSTAINING CAPITAL FORECAST: EXAMPLE SCENARIOS



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- NSP will continue to discuss with E1 and stakeholders to define the DR programs to be assessed in the Assumptions Development and Modeling phases of the IRP.

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[1] Customer behaviour-based peak shifting also through residential time of use, commercial time of use, and critical peak pricing rates.

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Blackburn Law

VIA EMAIL

August 23, 2019

Carly Currie
Nova Scotia Power

Dear Ms. Currie,

Re: M08929 – IRP Stakeholder Session #4

Further to your recent email, please find some questions arising from the Nova Scotia Power Stability Study for Renewable Integration Report that we would like to discuss at the upcoming Stakeholder Session:

1. Are the challenges associated with additional inverter-based generation dependent upon the resource type? Would the results have been the same if solar was added instead of wind?
2. Re: Table 4-1 (study cases), how did NSPI select these assumptions? For example, why was the NL import level set at 475 MW?
3. Please explain in more detail the modifications to Case 01 (pp. 39-40). Would this still be considered a "Light Load" case? Were any other load levels between 678 MW and 893 MW tested?
4. Are the results sensitive to the location of the conventional resources online? For example, do the inertia benefits depend on electrical proximity of the conventional resource to the evaluated location (Woodbine substation)?
5. Are the results sensitive to the location of the incremental wind?
6. In the evaluation of Case 04 with the additional tie (Section 5.2), were the same mitigation measures implemented as described in the base case (additional thermal unit, shunts switched off)?
7. In the examination of the cases with the additional 345 kV tie, does the additional tie change the level of MW import/export from/to New Brunswick?

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Please let me know if you have any questions or require any clarification.

Yours truly,

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Melissa P. MacAdam
for
E.A. Nelson Blackburn, Q.C.
Small Business Advocate

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ECONOMIC CONSULTING
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August 26, 2019

Carly Currie, Nova Scotia Power, Inc.
NSPI

Vincent Musco, Collin Cain, Nick Puga
Bates White Economic Consulting

Vía e-mail: Carly.Currie@nspower.ca

Subject: Bates White's Initial Questions for Stakeholder Session #4

Carly,

As requested, we provide some of our questions in advance of Stakeholder Session #4. These questions address three pre-IRP deliverables: (1) PSC's Renewable Integration Study; (2) NSPI's Existing Assets Sustaining Capital data; and (3) NSPI's DR Study from Efficiency One. We reserve the right to ask additional questions. We look forward to tomorrow's discussion.

1. PSC Renewable Integration Study

Our questions:

i. How has PSC addressed the impact of the Maritime Link, including additional transfers from NLH for sales into New Brunswick/ISO New England? Did PSC modeling consider any contractual transmission priority over the Maritime Link for firm NLH sales in the ISO New England market with respect to transmission for NSPI Supplemental Energy?

ii. How has PSC addressed and modeled NSPI's imports over the Maritime Link? Please distinguish between the NS Block energy and Supplemental Energy.

iii. How has PSC address the availability of transmission on the Maritime Link for NSPI to import Supplemental Energy? Has PSC modeled all firm commitments on the Maritime Link, other than those enjoyed by NSPI? And how has PSC modeled any non-NSPI firm transmission commitments on the NSPI system?

iv. Would the additional 345 kV line to New Brunswick have any impact on the expected impact of the Maritime Link operating in full with Muskrat Falls also operating in full?

v. How did PSC decide upon/develop the scenarios discussed in the "Study Results" section at pages 5-6?

vi. Please confirm that PSC did not consider any wind penetration scenarios beyond 1,000 MW. If confirmed, please explain why additional wind penetration was not considered.

vii. Were there any results of the PSC study that would imply new or changed reliability constraints on the NSPI system?

viii. Could the lack of consideration of synthetic inertia potential be understating the potential benefits of energy storage? (See page 8.)

ix. Did it PSC study the feasibility of Virtual Synchronous Generators (VSG), consisting of inverters with virtual inertia control algorithms with or without battery storage, in lieu of synchronous condensers, to accommodate higher penetration of wind?

2. NSPI's Existing Assets Sustaining Capital Data

i. Please explain the components of each year's sustaining capital cost.

ii. Regarding the CTs: NSPI projects $23.4 million in sustaining capital costs for the CTs the for three-year period (2020-2022). The next six years, the total sustaining capital is expected to be less than that—just $22.6 million. Please explain the assumptions behind this result.

iii. Regarding the hydro assets: NSPI projects $131.7 million in spending over the next four years (2020-2023) but just $50.2 million in spending over the following five years (2024-2029). Please explain the assumptions behind this result.

iv. Regarding the hydro assets: Please explain any result in which an asset is expected to have "0.0" in sustaining capital.

v. Regarding the thermal assets: Please explain the components of "Unit 0" costs.

vi. How do these *forecasts* compare to previous *forecasts* of sustaining capital for each individual year 2020 through 2029, inclusive?

vii. How do these *forecasts* compare to *actual* sustaining capital costs over the past ten years for each asset? Would unplanned maintenance costs be captured in *actual* sustaining capital costs?

3. NSPI's DR Study from Efficiency One

i. How will the results of the EE/DR potential study be incorporated in the IRP modeling?

ii. Do the base, low and high scenarios examined in the EE/DR potential study correspond to scenarios that are expected to be applied in the IRP modeling? If not, how will the EE/DR case results be mapped to IRP analysis scenarios?

iii. It is stated in 1.3.1 Program Design (page 17) that “this potential study is not intended to provide, nor does it have information on, detailed program designs.” Please clarify whether the study assessed NSPI’s existing EE/DR programs in developing the EE/DR potential estimates presented in the report.

iv. Regarding the caveat in 1.3.1 Program Design (page 17), that “[d]ifferent program designs and delivery mechanisms would inevitably result in different levels of adoption of efficient technologies…”, will NSPI in its IRP analyses assume new EE/DR programs to achieve increased EE/DR?

v. Regarding the bulleted item “Residential HVAC Fuel Switching” under 12.1 Energy Efficiency (page 118), please describe more fully the assumed “HVAC fuel switching measures that completely remove the end-use load from a home.” Were the associated estimates of EE technical and economic potential based on actual fuel costs faced by NSPI residential customers?

vi. What are the “significant market barriers to customer adoption” of HVAC fuel switching?

EfficiencyOne questions and clarifications for NS Power re: 2019 IRP prework by E3 and PSC

Capacity Study

Please describe assumptions that were used in DR dispatch within RECAP.

Does NSP consider it to be an economic decision to dispatch all available resources, including the highest cost fuel dispatch, before employing DR?

Please describe the methodology used to dispatch within RECAP and why DR is used as a last resort.

Why were solar profiles limited to 2008-2010?

Is it assumed that no DR options exist for dispatch in 2020 as per slide 14 dispatchable resources?

Is Maritime Link/Muskrat Falls base block energy and/or other energy purchases across the Maritime Link considered to be dispatchable in the RECAP model?

Is Wreck Cove assumed to be available to produce 500-1100 MWh every day of the year in the model? Or did E3 consider a seasonal shape applied based on storage and historical hydrology?

Why are there no transmission constraints assumed in Nova Scotia?

Would reserve requirements change after the impact of DR is considered?

Please explain the definition of “Effective Capacity” and why in many cases it matched with nameplate capacity (Slide 21). Effective capacity changes on slide 23. Please explain.

How does RECAP account for the need to “recharge” energy storage capacity and potential loss of availability?

Based on changes to weather patterns in recent decades, how is using prediction of weather going back to 1950 a reliable assumption for weather calibration in the RECAP model? Renewable generation predictive modelling will likely have a wide array of outcomes based on more recent weather trends vs tracing back to 1950.

Please explain why ELCC (marginal ELCC) becomes zero after only 100MW of DR are on the system (slide 42 and 43) and please explain why ELCC changes between the 2 charts when DR capacity remains constant

How is the ELCC diversity benefit allocated between resources? To which resources is it allocated? What are the implications of different methods of allocation?

Does diversity in the types of demand response programs produce a larger ELCC diversity benefit than a single demand response program?

Is NSP’s intent to require each IRP Candidate Resource Plan to meet the PRM range of 17.8% to 21.0%, or the LOLE of 0.1 days/yr?

Would it be possible for a feasible Candidate Resource Plan to achieve the LOLE of 0.1 days/yr with a PRM lower than 17.8%?

Is it correct that a portfolio with less than 17.8% PRM might still achieve a 0.1 days/yr LOLE?

Supply Options Study

The Federal government released a draft of new national clean fuel standards, including liquid fossil fuels and solid fossil fuels. Will these regulations be considered for the IRP modelling, assuming there are impacts to NS Power? (although not enacted, NSP should consider the impact of the regulations as drafted to its overall IRP sensitivities)

Why is demand response not considered to be a viable resource option?

Please confirm that 2030 capital costs are discounted to $2019

Renewable Stability Study

Curtailment of wind and dispatchable wind are solutions in other jurisdictions, as are Remedial Action Schemes. Were these options considered in the study to increase integration of additional renewable/variable output generation?

What level of DSM was assumed for the study?

- How do demand savings achieved through demand side management affect renewables integration?
- How does the level of demand response affect renewables integration?

DR Program Assumptions Development

How were assumptions developed regarding the enrollment fee as well as the annual incentive relating to hot water heaters?

What costs are included in the $1.49/MW program cost? And was this discounted over the 25 years?

Are the costs inclusive of expected costs at the system operator level to enable hot water heater direct load control?

What technology is anticipated to be used for the control devices?

Did E3 use its own forecast for EV sales in Nova Scotia or was this taken from the NS Power Load Forecast?

Please provide assumptions for EV program costs over the 25 years

How was E1 information on DR programs, and the draft potential study, used to inform the 3 DR programs?

Please provide detailed assumptions with sources for NSP's DR program analysis. It may be beneficial to walk-through these assumptions in the next pre-IRP stakeholder session time permitting. More specifically, can NSP provide further details on the following:

- Annual EV forecast through 2045 (if different than the forecast used in the 2019 NSP Load Forecast)
- Event opt-out assumptions
- Program attrition assumptions
- Recurring costs as technologies such as water heaters, electric vehicles, and advanced controls reach their end of life
- All other program cost assumptions
- How the total peak shaving potential for each DR program has been calculated

The footnote on the first page of the DR Program Overview document references behavior-based peak shifting through time-varying rates. Have the peak shaving potential and program costs been quantified for these programs?

Energy Futures Group, representing E1, Draft questions for NSP re IRP prework by E3 and PSC

Capacity Study

What process did E3 undertake to determine whether temperature was a significant driver of renewable production?

What information can E3 provide about the duration, frequency, and seasonality of modeled loss of load events in RECAP? I.e. are the events that tended to contribute to loss of load, but for an adequate reserve margin, "sustained multi-day periods of high loads and corresponding low renewable generation" or were they caused by some other factor and shorter in duration?

In RECAP, do the renewable production draws result in convergence to a particular capacity factor over a given period, e.g, a year?

Regarding Table 15, could E3 perform additional scenarios assuming significantly different mixes of EE, DR, storage, renewables, etc.?

Supply Options Study

Could E3 provide the pro forma model that it developed for Nova Scotia Power?

What factors make the estimated cost of pumped hydro, "informed by NSPI engineering estimates", so much lower than the other estimates cited by E3?

What are the assumed operating costs for coal and biomass co-firing?

Will the "sustaining capital" investments in the Addendum to the study be modeled in Plexos?

Questions for the Pre-IRP Process

Capex for the Cost of Wind

Please expand upon the rationale given at the session on August 8, 2019 with respect to the wind capex numbers being relatively constant over the past ~ 8 years (~$2 million CAD) while PPA prices in cost per kwh in Nova Scotia have declined by a third to nearly 2/3 over the same period of time.

[as reference for prices 8 years ago see price assumptions for capex COMFIT large wind tariff proceedings for 13.5 cents per kwh and for price assumptions 5-6 years ago see rate for South Canoe ~ 7.5 cents per kwh [1] and as reference for prices today please reference any information you have on Emera's RFP responses for the Atlantic Link project believed to be in the range of 5 – 6 cents per kwh]

Value and Implications of the Maritime Link

Please describe the implications for balancing wind once market priced hydro from Muskrat Falls is available in 2020/2021? Will the presence of the market block be helpful in integrating the current wind on the system (600 MW), and if not why not? And what role would the market block play in helping to balance additional invertor-based electricity resources (wind or solar or tidal) [please reference the value of the Nalcor/NS Power annual RFP process and how it could be used to help balance wind].

Implications from non-utility (behind the meter – across the meter) Distributed Energy Resources

At least one utility in Nova Scotia (Berwick) is piloting a regime where commercial and residential customers will have renewable generation, storage, and control systems to direct the production of electricity to and from the battery/grid/customer use. The pilot was a winner in the recent Canada-UK Power Forward Challenge. The pilot is setting out to prove the cost and benefit of such systems. If these technology packages (combined to deep efficiency retrofits) prove attractive to customers, they may significantly reduce the load requirements for customers able to afford the capital costs. Will the IRP process deal with the risks and benefits from such customer choices/utility opportunities? And if so at what stage and will there be an opportunity to introduce evidence on such matters?

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[1] https://novascotia.ca/news/release/?id=20120802003

August 26, 2019

Carly Curry
Nova Scotia Power

Cc Regulatory Affairs

Via email

Re: comments for Pre-IRP Stakeholder Session #4

Thank you for the opportunity to participate in the pre-IRP workshops and discussion. In anticipation of Session #4 on August 27th, 2019, we offer the following comments.

Thermal Energy Storage

The Verschuren Centre believes that thermal energy storage can play an important role for determining the lowest cost option for a reliable high-renewable electricity grid in Nova Scotia. Thermal energy storage involves the storage of heat or cold at or near where it will be used. For Nova Scotia, our electricity system peak occurs in the winter, in large part due to demand for spacing heating and hot water.

Thermal storage has attributes of both energy storage and demand control, but also limitations, such as that it cannot provide electrical power back to the grid. It is also generally based on lower cost materials such as water, brick, soil, salt and concrete. Thermal storage units tend to have longer design lives than batteries.

There are many types and sizes of thermal storage. For an example, consider the specific Steffes Electro-Thermal Storage (ETS) unit (Model 4120 – 19.2kW version) that has been installed and operating in NS for a number of years. This unit is at the smaller end of the range of sizes Steffes provides. It has 120kWh of thermal storage capacity, with a 19.2kW input. Assuming an installation cost of $10,000 per unit, this system would be significantly less expensive those demand control and energy storage options considered in the preliminary documents.

The following are some specific comparisons:

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- In comparison to the Demand Response Draft Assumption Summary (Attachment 3 - Slide 1), this ETS unit would have closer to 19.2kW of peak shaving capacity. To achieve a MW of demand response at this rate, approximately 52 units would be needed, at a cost of $0.52M/MW. With a long design life, the lifetime cost would be significantly less than any options currently listed.

- In comparison to the Energy Storage options listed in the E3 Supply Options Study (Attachment 2 – Slide 11), this ETS example would have a cost of $520/kW , which much lower than the range considered ($814-$2,700/kW). Based on its input capacity, this ETS unit would have over 6 hours of storage. Actual heating demands may be lower than the input capacity (19.2kW) and therefore allow for higher hours of storage.

- With respect to the Effective Load Carrying Capability (ELCC) of storage and demand response (E3 Capacity Study Overview –Slide 25), this ETS example is in the higher range of hours of energy storage (6-12hours) and is available for more than 20 calls / year considered in the demand response graphic. Therefore, this ETS would be at the upper range or higher in Effective Load Carrying Capability than those attributes graphed in the presentation, and a significant amount of investment would be available in thermal storage before diminishing returns applied in a material manner.

- The cost effectiveness advantage is even more drastic when compared to other storage/capacity options based on duration, versus capacity. Since the cost of additional material is low in an ETS system, the cost per kWh is also low. The ETS example from above yields an installed capital cost per kWh of $83. See the graph from Attachment 2, slide 47 for graphic comparison:

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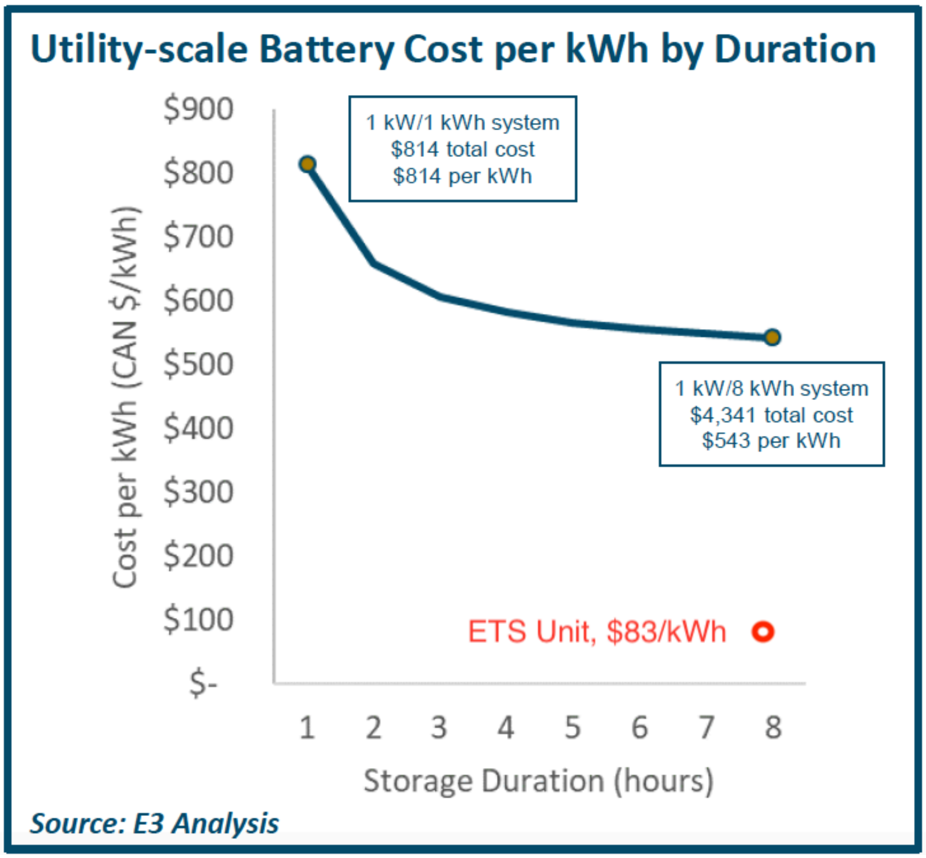

Thermal storage not only can be very cost effective, it also is well aligned to meet two key challenges that will be faced by the grid in the coming decade:

- How to integrate more wind energy, and
- How to electrify space heating to reduce emissions.

Thermal energy storage includes a broad range of technologies, materials and applications. Based on the cost effectiveness and particular fit with our grid needs in Nova Scotia, we suggest that this topic be explored in more detail in advance of the IRP Assumptions phase completion. The Verschuren Centre would welcome participation in additional conversations to better understand the range of opportunities in this sector with any IRP stakeholders.

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Additional comments

In addition to the above, the Verschuren Centre has the following additional comments/questions:

- Demand Response Customer Incentives. What are these incentives based on? Who owns the equipment in these models? There many are benefits to both customer owned models, or utility owned models. It would be important for customers to receive an appropriate benefit. In some markets (Tempus Energy – UK) demand response equipment is owned by the utility, and participating customers receive a reduced energy rate as a result.

- Demand Response - Water Heater – adding additional tank could provide more storage and flexibility, and fewer customer issues, than simple control/timing of existing tanks.

Thank you again for the opportunity to participate and we look forward to the discussion on August 27th,

Sincerely,

Daniel Roscoe, P.Eng
Lead – Renewable Energy
Verschuren Centre for Sustainability in Energy and the Environment

From: Milojevic, Mila
To: Aaron Long; Currie, Carly
Cc: Don Regan; Meaghan Barkhouse; Godbout, Nicole; MacDonald, Lia; Dylan Heide
Subject: RE: IRP Question
Date: Thursday, August 8, 2019 11:02:14 AM

Good morning Aaron,

Confirming receipt of your email. I'm also copying Carly Currie as she'll be tracking questions/feedback for us.

We'll get back to you on your request as soon as possible.

Cheers!
Mila

Mila Milojevic | Manager, System Planning | **Nova Scotia Power**
Office: 902.428.6853 | Cell: 902.717.0763
mila.milojevic@nspower.ca

From: Aaron Long <aaron.long@municipalenergy.ca>
Sent: Wednesday, August 7, 2019 11:25 AM
To: Godbout, Nicole <NICOLE.GODBOUT@nspower.ca>; Milojevic, Mila <Mila.Milojevic@nspower.ca>; MacDonald, Lia <Lia.MacDonald@Emera.com>
Cc: Don Regan <dregan@berwick.ca>; Meaghan Barkhouse <mbarkhouse@townofantigonish.ca>; Dylan Heide <Dylan.Heide@townofmahonebay.ca>
Subject: IRP Question

`**This is an external email - exercise caution**`

Nicole, Mila and Lia,

Recognizing that the telecon is running over time, we thought it would be best to send this request along via email.

Can you share the following information (from the E3 work, or your own data if this is readily available), for the last 5 years of operational experience:

Date and hour of peak NSPI system load for each of the last 5 years/winters, what the NSPI load actually was, and what the capacity factor of the wind was (actual production of NSPI/IPP/COMFIT wind divided by nameplate of that same group) during that peak time?

We are interested in this information to compare the recent actual experience that you've had with what E3 is proposing for the longer period of study.

Thanks so much. Sometimes my emails get caught in spam, so can you confirm receipt of this email?

Kind regards,

Aaron Long, P.Eng., MSc, MBA
Director of Business Services
Alternative Resource Energy Authority
1-902-497-1447
aaron.long@municipalenergy.ca

BATES WHITE
ECONOMIC CONSULTING
2001 K Street NW North Building Suite 500, Washington, DC 20006 main 202.408.6110 fax 202.408.7838

September 13, 2019

Carly Currie, Nova Scotia Power, Inc.
NSPI

Vincent Musco, Collin Cain
Bates White Economic Consulting

Vía e-mail: Carly.Currie@nspower.ca

Subject: Bates White's Comments on Pre-IRP Documents, Discussions to Date

Carly,

As requested, we are providing our comments on the pre-IRP documents and discussions to date. We note that not all of our prior written questions and requests have been answered;[1] as such, our comments are necessarily abridged and cannot be completed until those questions and requests are addressed. We note such deficiencies below.

As a preliminary matter, we appreciate NSPI's collaborative efforts to date and NSPI's efforts to share this memo with all stakeholders and to provide us access to written comments provided by other stakeholders. We also appreciate being included in the upcoming pre-IRP work, including development of the "terms of reference." We understand there are several steps necessary to accomplish before the IRP process can begin, including addressing stakeholder questions and concerns, and look forward to working with NSPI, the Board, and stakeholders in this work.

We break out our comments across each of the five pre-IRP reports: (1) Energy and Environmental Economics' ("E3's") Planning Reserve Margin and Capacity Value Study; (2) E3's Resource Options Study; (3) NSPI's Sustaining Capital Data; (4) EfficiencyOne's Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045; and (5) PSC North America's ("PSC's") Nova Scotia Power Stability Study for Renewable Integration Report.

1. E3's Planning Reserve Margin and Capacity Value Study

Planning Reserve Margin

[1] See Bates White's August 26 Memo to NSPI; see also Vincent Musco's August 30 email to NSPI.

The planning reserve margin (PRM) necessary to maintain a given level of reliability is a function of a number of resource and system variables that are themselves being evaluated in the IRP process. For instance, all things equal, a system with larger supply resources will cause the required PRM to be higher. Higher resource forced outage rates will also cause required PRM to increase. As we note elsewhere in our comments, we believe it's essential for the IRP process to consider supply scenarios in which NSPI relies on a smaller number of units with improved availability.

While we understand that the PRM target is a necessary input to developing NSPI's resource plan, we do not believe that there is a single, hard PRM value that would be applicable across the various resource scenarios that NSPI needs to evaluate, particularly since some resource options may imply a lower target PRM. For this reason, we recommend that NSPI apply more conservative – i.e., lower – PRM values in its IRP evaluations. If the evaluation based on a lower PRM value identified a resource plan with periods in which total supply is at or very near the PRM, such a case could be examined more closely to determine whether reliability would potentially be compromised.

We also note that E3's definition of "operating reserves" is unclear, as they acknowledged during the August 7 stakeholder meeting. Notwithstanding our recommendation above, NSPI should clarify and reconcile E3's reserve definitions and assumptions in conducting its analysis and reaching its conclusions with reserve types that are required by NERC/NPCC and with those categories of operating reserves discussed in our Audit Report.

On page 20 of E3's Planning Reserve Margin and Capacity Value Study it is stated that, "in the case of NSPI, investments in capacity tend to be much lumpier than changes in annual peak load and so it may be economically optimal to build/contract/maintain capacity in exceedance of the 20% PRM in order to ensure future capacity is available economically." It is our view that the IRP process should be focused on ways to minimize the costs imposed on customers, including costs associated with being unnecessarily long on capacity. Given the ongoing, rapid changes in resource technologies and costs, we believe there may be more risk in pursuing a resource plan that locks in excess capacity than in pursuing one that maintains flexibility to take advantage of future resource options.

We understand that certain E3 inputs – DAFOR, maintenance schedules—see Table 4 on page 24 and Table 9 on page 29 – came from NSPI. We would like to confirm that the data provided by NSPI is consistent with the data used in the BCF update proceeding (M09288) for all relevant years.

Electric Load Carrying Capability

The E3 study presents Electric Load Carrying Capability (ELCC) estimates for wind, solar, energy storage, and combinations of wind+storage and solar+storage. It is not clear whether this would correspond to five resource addition options for application in the IRP modeling or whether the model would be selecting from three options – wind, solar and storage. Conceptually, it is not apparent that storage added alone to the NSPI system, which has substantial existing wind resources, would have a different ELCC than storage when matched with new wind additions. NSPI should specify how it is applying the ELCC values for the respective resource options within its IRP modeling.

The E3 study provides ELCC estimates for demand response (DR) resources. A separate study by EfficiencyOne (addressed below) estimates volumes of achievable DR and energy efficiency potential. NSPI should clarify whether DR will be modeled as a distinct resource alternative with ELCC values, or as a modification to load, or otherwise.

2. E3's Resource Options Study

Bates White offers the following comments:

- During the August 7, 2019 IRP stakeholder session in which E3 presented the results of this study, we requested that E3 provide a detailed breakdown of its cost estimates for each new technology that were presented generally on slides 8 and 9 of the study. We have yet to receive this data. Without it, we will not be able to adequately assess whether any of E3's cost estimates for any of the technologies contained in the study are reasonable.

- On slide 6, E3 identifies "Fixed costs" that are "expenditures required to install and maintain generating capacity, independent of operations" for new resources. NSPI should reconcile the costs associated with "maintaining generating capacity, independent of operations" provided by E3 for new resources, and NSPI's own sustaining capital cost assumptions for its existing asset fleet. (See also our comments on NSPI's Existing Assets Sustaining Capital Data below.)

- In most cases, E3 assumes a cost per-kw for a given technology given a particular size (e.g., a combined-cycle unit of 145 MW is assumed to have a capital cost of $1,688/kW—see slide 66). In the IRP, it will be important to ensure that (a) smaller units or configurations be considered which, though they may have a higher $/kW cost, could address the "lumpiness" issue associated with the PRM, and (b) larger units/configurations be considered, and done so in a way that captures economies of scale. Regarding this second point, larger units have lower $/kW costs than smaller units. So, for example, if a 300 MW capacity need were identified, a single 300 MW combined-cycle unit would be more cost-effective than adding two 145 MW combined-cycle units.

- E3 should explain the currency conversion assumptions it used. For example, E3 claims that the "NREL 2018 ATB" cost for a 50 MW CT – Frame is $1,226 (CAD); however, this would suggest an exchange rate of at least 1.39 and as high as 1.42.[2]
- NSPI should ensure that E3's data is up to date. The 2018 NREL ATB Study is based on data as old as 2014. We note that the multiple stakeholders raised concerns with the onshore wind assumptions put forth by E3 as inconsistent with recent provincial wind prices. We would also point to examples such as Maxim Power's recently-announced 204-MW simple cycle gas turbine, which has a total capital cost of $706/kW (CAD) (without financing costs).[3]
- E3's capital cost estimate (at slide 48) for 4-hour duration battery storage may conflict with its own recommendations elsewhere. On slide 48, E3 recommends a $2,325/kW capital cost;[4] however, in its 2018 WECC Survey, it recommends $1,500 USD/kW for standalone 4-hour energy storage, which at a conversion of 1.33 USD/CAD, would equal $1,995 CAD/kW. The reason for this deviation is not provided.
- NSPI should consider modeling longer duration storage options (beyond 4 hours).
- Similarly, E3 should provide further support for its estimates of future battery storage costs, which E3 acknowledged are based on Lazard estimates (slide 49).
- The IRP should include pumped storage options (slide 57) that are outside Nova Scotia. As E3 notes, pumped storage costs can vary considerably and are highly site-specific.
- It is not clear why E3 limited its analysis of coal-to-gas conversions to a few specific units (slide 61). A more thorough analysis should be required for the IRP.

[2] Exchange rate derived from 2018 NREL ATB data for CTs, with and without financing. https://atb.nrel.gov/electricity/2018/index.html?t=cg
[3] See SNL Financial here: https://platform.mi.spglobal.com/web/client?auth=inherit#news/article?id=54119854&KeyProductLinkType=4.
[4] See slide 38: https://www.wecc.org/Administrative/E3-WECC%20Resource%20Cost%20Update-201905%20RAC%20DS%20Presentation.pdf

- E3 noted during the August 7 stakeholder meeting that they had not developed any estimates for the cost of incremental firm natural gas pipeline capacity for the IRP. This is a critical assumption that should be discussed in advance of the IRP.

3. NSPI's Existing Assets Sustaining Capital Data

Bates White offers the following comments:

- We note first that we have requested to see a more detailed breakdown of the components of sustaining capital cost provided by NSPI. We await that response in writing.
- It appears that NSPI's sustaining capital costs include only those costs/investments related to planned refurbishments. (NSPI has noted to date that such costs included the expected refurbishment costs, AFUDC, and "administrative overhead," though it is unclear to us how these numbers are derived, despite having reviewed the most recent ACE filing and 10-year system outlook study.)
- NSPI's sustaining capital costs do not seem to include all *avoidable* costs, i.e., those costs that would be avoided if the plant were mothballed or shut down. This should be remedied for the IRP. Moreover, NSPI's sustaining capital estimates will have to be consistent with E3's defined costs associated with "maintaining generating capacity, independent of operations" provided by E3 for new resources.
- Capital investments by NSPI appear to be underway (or recently finished) on numerous assets in its fleet, including the CTs and Wreck Cove. It is important that these costs – unless they are both approved by the Board *and* already expended – be considered in the IRP process – i.e., they should be treated as potentially avoidable.

4. EfficiencyOne EE/DR Study

Given NSPI's estimation that it faces a near-term capacity deficit (according to the 2019 10-Year System Outlook), it will be particularly important to assess the potential for energy efficiency (EE) and demand response (DR) programs to partially or fully mitigate such deficits, as well as the potential for such programs to displace longer-term generation and transmission investments. To date, we have seen no explanation of how the results of the EE/DR potential study will be incorporated within the IRP evaluation process. Based on the contents of the EfficiencyOne report, we infer that EE and DR will not be reflected in the IRP as alternatives for the model to select cost-effectively in place of new and existing supply resources. Rather, it appears that the EE/DR potential may be reflected in projected system load. It will be important for NSPI to clearly specify the EE/DR scenarios that are modeled and to detail how such scenarios correspond to and/or deviate from the base, low and high scenarios examined in the EE/DR potential study.

We recommend that NSPI explicitly evaluate and report on the potential for EE/DR to mitigate near-term capacity deficits and to displace longer-term investments in existing and new supply resources as well as transmission.

5. PSC Renewable Integration Study

The PSC Renewable Integration Study appears to provide useful context for operation of the NSPI system with the current topology and resource mix (including Maritime Link). Several aspects of the study and its results are important to emphasize:

- The study does not establish any volume limit to additional wind resources on the NSPI system. Rather the study recommends an expanded analysis to explore this question.
- While the study finds that addition of a second 345kV tie to New Brunswick (Onslow to Salisbury) would enhance the ability of the system to accommodate at least 400MW of additional wind resources, the study does <u>not</u> conclude either that the additional tie is *required* to accommodate more wind, or that 400MW represents a maximum incremental addition of wind.
- It does not appear that the study considered synthetic inertia potential via Virtual Synchronous Generators (consisting of inverters with virtual inertia control algorithms), in place of synchronous condensers, to accommodate higher penetration of wind. While rotating inertial mass plays an important role in supporting system stability, there is increasing recognition that synthetic alternatives can be effective and cost-efficient. Any expanded analysis should evaluate such alternatives.
- The study asserts that "[i]ntroducing larger volumes of power electronic devices into the system has known adverse effects with regards to, for example, harmonic distortion levels on the system." An expended study should fully address the factual basis for this in the context of the NSPI system, whether new synthetic inertia methods mitigate the significance of this issue, and the relevance to greater wind integration and the IRP more broadly.

- The study notes that the implications of potential grid code modifications were not addressed. This should be incorporated in any expanded analysis.

Blackburn Law

VIA EMAIL

September 12, 2019

Carly Currie
Nova Scotia Power

Dear Ms. Currie,

Re: M08929 – Comments on draft Deliverables

The Small Business Advocate (SBA) appreciates that the pre-IRP process has enabled stakeholders to provide feedback and collaborate on assumptions, methods, and planning priorities, before the direction of the formal IRP process has been set. Please accept these comments regarding the draft deliverables prepared in relation to the 2020 IRP.

At the August 7th and August 27th IRP stakeholder sessions, Nova Scotia Power Inc. (NSPI) presented draft versions of several pre-IRP deliverables:

- E3 Planning Reserve Margin (PRM) and Capacity Value Study
- E3 Resource Options Study
- NSPI Demand Response Assumptions
- PSC Nova Scotia Power Stability Study for Renewable Integration Report

NSPI emphasized during the sessions that the reports are in draft form, and that comments received by stakeholders would be incorporated into the final reports. In their final form, these studies will provide the basis for the assumptions and analysis structure used in the IRP. The SBA believes that there are several areas where certain additions would improve the value of these studies to the IRP process.

Planning Reserve Margin (PRM) and Capacity Value Study

The PRM is a critical component of the IRP process because it defines the goal that the plan is striving to achieve. The SBA is generally supportive of the scope and methods of the PRM, but provides the following recommendations for improvements which would give stakeholders a more complete view of the trade-offs inherent in long-term resource decisions:

1. The SBA believes the PRM study should include expanded analysis on interties. The draft PRM study included conservative assumptions related to tie benefits from interconnections with New Brunswick and the Maritime Link. In the example of New Brunswick, E3 assumed no tie benefit, assuming that New Brunswick is likely to experience resource shortages coincident with Nova Scotia. This assumption should be based on study and analysis of historical shortages, as well as reasonable forecasts of system changes in the

future. By relying on conservative assumptions, NSPI may be failing to recognize the reliability value the interconnection can provide and therefore over-planning for capacity need. A more detailed study of the potential tie benefits of the interconnection would allow for a more comprehensive assessment of the costs and reliability risks of future resource decisions.

2. The PRM study should be clarified regarding the interaction between planning and operating reserves. The draft PRM study concludes that the PRM should be 17.8%-21.0%, depending on the amount of capacity held out for operating reserves. The relationship between operating reserve level and reliability is not sufficiently discussed in the study. The PRM study does note that the model will shed load before allowing the level of operating reserves to dip below the threshold in order to avoid significant grid issues (p. 40), but these issues are not described or explored in the study, so there is insufficient information for stakeholders to assess the material difference between a 17.8% PRM and 21% PRM future.

3. The SBA notes that the Electric Load Carrying Capability (ELCC) analysis should be modified to capture anticipated changes to load shape over time. The ELCC calculations are conducted based on historical load shapes. These load shape assumptions appear to have a significant impact on ELCC values, particularly for storage and demand response (DR) resources at higher penetrations. The study should conduct sensitivity analysis assessing the impact of shifting load shapes with electrified heat, transportation, and with greater demand flexibility and dispatchability. This analysis could show a higher (or lower) ELCC for these resources, thus impacting resource planning outcomes.

NSPI Demand Response Assumptions

The SBA believes that to effectively conduct least-cost resource planning, the DR assumptions will be critical. Growth in intermittent and distributed generation, the electrification of transportation (and potentially heat), and the societal preference for non-emitting generation are trends that place a premium on load flexibility. Given the indication that battery storage is likely to be included in the portfolios to be evaluated in the IRP, we feel it is important that the DR assumptions be fully vetted by stakeholders prior to the analysis. NSPI has raised several concerns regarding high penetrations of intermittent resources, and the stakeholder session primarily discussed storage as a solution. Demand response utilizing direct load control can be a much more economical resource that serves a similar purpose, but NSPI so far has only presented very high-level assumptions that will be used in the IRP. There are several direct load control options that NSPI can consider beyond water heater load, including air conditioning, electrified heating, commercial refrigeration and even certain industrial loads.

Nova Scotia Power Stability Study for Renewable Integration Report

The PSC renewable integration study is an important study that provides information essential to the long-term strategic planning process. As load profiles change and grid supply becomes more reliant on renewables, it is critical to address reliability and system strength concerns. The renewable integration study provides new information about the capability of the system to integrate additional renewables. In order to provide additional value to the planning process, the SBA believes the study should be expanded. It is our understanding that the study showed system integrity issues under some scenarios, even at the current 600 MW level of renewable energy inverter-based generation. This needs to be examined closely as enabling investment may be necessary in the near term, much earlier than a new interconnection could be planned, approved, constructed, and energized.

NSPI's presentation of the renewable integration study to stakeholders noted multiple areas in which more analysis is needed to fully assess the ability of the grid to reliably integrate more renewables, and the potential solutions to reliability issues that will arise. For example, the study determined that with an additional 345kV interconnection with New Brunswick, Nova Scotia can integrate at least 1,000 MW of inverter based-generation. However, the study assumed the New Brunswick grid will stay as it is today and did not test whether this intertie continues to deliver the same benefits if New Brunswick increases the portion of inverter-based resources in its portfolio. The study also did not evaluate the reliability of the system with combinations of an additional tie with synchronous condensers. Finally, the presentation materials note that additional studies and scenarios are required to ensure that the system can be reliably operated with sufficient power quality with a higher penetration of renewables. This additional analysis will be critical, given the interest by some stakeholders to encourage more emission-free generation.

While this study provides high-level insight into grid challenges and capabilities, it does not yet provide enough analysis or detail to base long-term investment decisions. Therefore, while it can assist with the strategic-level discussions during the IRP process, additional study will be required to fully understand the costs, benefits, and tradeoffs of different solutions for integrating additional renewables.

The purpose of the 2020 IRP is to analyze the key long-term issues affecting energy cost for Nova Scotians and the environmental impact of meeting their needs for energy. These studies provide a strong foundation. The SBA looks forward to further participation and collaboration in the NSPI 2020 IRP process.

Yours truly,

BLACKBURN LAW

E.A. Nelson Blackburn, Q.C.
Small Business Advocate

Alternative
RESOURCE ENERGY AUTHORITY

Mila Milojevic
Manager System Planning
Nova Scotia Power Inc
Delivered via email to mila.milojevic@nspower.ca

13 September 2019

Re: Letter of Comment Regarding Current IRP

Dear Mila,

The Alternative Resource Energy Authority (AREA) would like to thank NSPI for conducting what we believe is the most inclusive IRP process to date. The assembled group of stakeholders is effectively planning a key component of Nova Scotia's future competitiveness in a global marketplace and such a process requires the host to accept input from across the spectrum. We are pleased with NSPI's hosting of the pre-IRP sessions, subsequent staff dialogue and access to external consultants.

AREA is owned entirely by the Towns of Antigonish, Berwick and Mahone Bay, each of which owns and operates its municipal electric utility. We are participating in the current IRP to ensure that the Provincial electrical system decarbonizes at the least possible costs to Nova Scotians, their employment and our institutions. Our specific communities require a vibrant, industrious Nova Scotia in order to thrive themselves, which is enabled by having access to cost effective clean energy.

With this objective in mind, we request that the IRP consider project financing structures beyond traditional NSPI ownership. Based on our direct experience, capital is available at rates lower than typically associated with NSPI ownership and this will lead to reduced renewable energy generation and integration costs.

Also based on our experience, the cost to build more wind energy in Nova Scotia is much less than that stated in the provided reports. NSPI affiliates should be well versed in such costs, having conducted an RFP for renewables for the Atlantic Link a few years ago. Costs have dropped since that time. Furthermore, existing sites in Nova Scotia have expansion potential, enabling even lower costs to build and operate incremental wind energy assets. Installed costs should be less than $1.5 million CDN per MW with a net capacity factor in excess of 40%.

We are reserving our comments on the ELCC for renewables until we receive the requested data. AREA recognizes that NSPI is managing storm response activities after Hurricane Dorian, and we look forward to further communication exchanges with NSPI staff when you are ready.

Thank you for considering our input.

Regards,

Aaron Long

Aaron Long
Director of Business Services

Alternative Resource Energy Authority, c/o Town of Antigonish
274 Main Street, Antigonish NS B2G2C4

Alternative
RESOURCE ENERGY AUTHORITY

Cc:

Lia MacDonald, Senior Director Enterprise Asset Management, NSPI
Carly Currie, Regulatory Project Manager, NSPI
Nicole Godbout, Director of Regulatory Affairs, NSPI
Jeffrey Lawrence, Chief Administrative Officer, Town of Antigonish; Secretary, AREA, jlawrence@townofantigonish.ca
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Dylan Heide, Chief Administrative Officer, Town of Mahone Bay, Dylan.heide@townofmahonebay.ca
Meaghan Barkhouse, Dir. of Corp. Services, Town of Antigonish; Treasurer, AREA, mbarkhouse@townofantigonish.ca
Don Regan, Manager Town of Berwick Electric Commission, dregan@berwick.ca

Planning Reserve Margin and Capacity Value Study

Nova Scotia Power Inc. July 2019

Energy+Environmental Economics

Planning Reserve Margin and Capacity Value Study

July 2019

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Project Team:
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Shenshen Li
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Table of Contents

Acronyms

DAFOR	Derated Adjusted Forced Outage Rate
DR	Demand Response
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
FOR	Forced Outage Rate
GHG	Greenhouse Gas
ISO	Independent System Operator
LOLE	Loss-of-Load Expectation
LOLF	Loss-of-Load Frequency
LOLP	Loss-of-Load Probability
MTTF	Mean Time to Failure
MTTR	Mean Time to Repair
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NSPI	Nova Scotia Power Inc.
PRM	Planning Reserve Margin
RA	Resource Adequacy
RECAP	E3's Renewable Energy Capacity Planning Model
UARB	Nova Scotia Utility and Review Board

Executive Summary

This study provides an update to several important assumptions to be used by Nova Scotia Power Inc. (NSPI) in the integrated resource planning (IRP) process to ensure that NSPI maintains an appropriate level of resource adequacy so that it can continue to provide reliable and affordable power to its customers. Specifically, this study provides an update of the following planning assumptions:

- Planning Reserve Margin (PRM)
    - The quantity of planning reserves that should be held above the forecasted annual peak load, calculated as a % of annual peak
- Effective Load Carrying Capability (ELCC) of dispatch-limited resources
    - The expected contribution toward the planning reserve requirement from the following dispatch-limited resources
        - Wind
        - Solar
        - Battery Storage
        - Demand Response

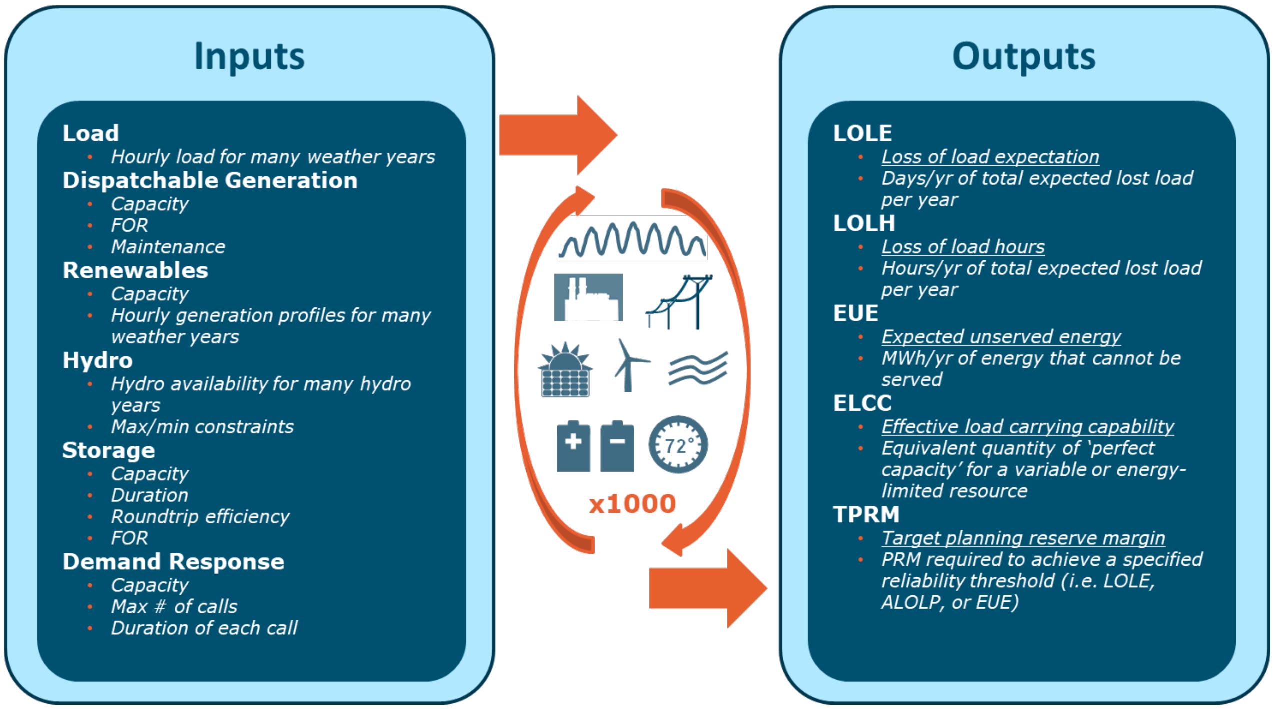
Background and Approach

Resource adequacy is the ability of an electric power system to serve load across a broad range of weather and system operating conditions, subject to a long-run reliability standard. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability such as the variable and intermittent production of renewable resources. Ensuring an appropriate level of resource adequacy is an important goal for utilities seeking to provide both reliable and affordable service to their customers.

NSPI currently plans to meet a 1-day-in-10-year reliability target, meaning that not more than 1 day out of every 10 years should experience a loss of load event due to load + operating reserve requirements exceeding available generation. Adherence to this standard is measured by the metric *loss of load expectation* (LOLE) which calculates the average number of days per year an electricity system is expected to experience loss of load. A system with an LOLE less than or equal to 0.1 days/year is compliant with the 1-day-in-10-year standard. After a jurisdictional review of resource adequacy planning standards across North America, E3 finds that this 0.1 days/year LOLE standard is in line with industry best practices.

This study assesses the resource adequacy the NSPI system using E3’s Renewable Energy Capacity Planning (RECAP) model. RECAP is a loss-of-load-probability model developed by E3 that has been used extensively to test the resource adequacy of electric systems across the North American continent, including in California, Hawaii, Canada, the Pacific Northwest, the Upper Midwest, Texas, and Florida. RECAP was developed specifically to address the needs of a changing electricity sector by incorporating the unique characteristics of dispatch-limited resources such as wind, solar, hydro, battery storage, and demand response into the traditional reliability framework.

RECAP calculates reliability metrics by simulating the electric system with a specific set of generating resources and loads under a wide variety of weather years, renewable generation years, and stochastic forced outages of electric generation resources and transmission. Correlations enforced within the model capture linkage among load, weather, and renewable generation conditions. Time-sequential simulation tracks the state of charge and energy availability for dispatch-limited resources such as hydro, energy storage, and demand response. By simulating the system thousands of times with different combinations of these factors, RECAP provides robust, stochastic estimation of LOLE, target PRM, ELCC and other reliability statistics provided in this report.

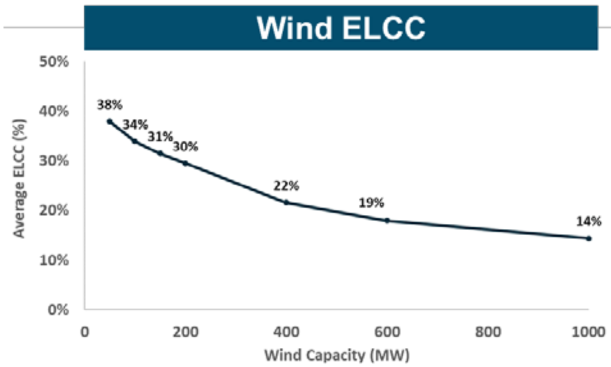


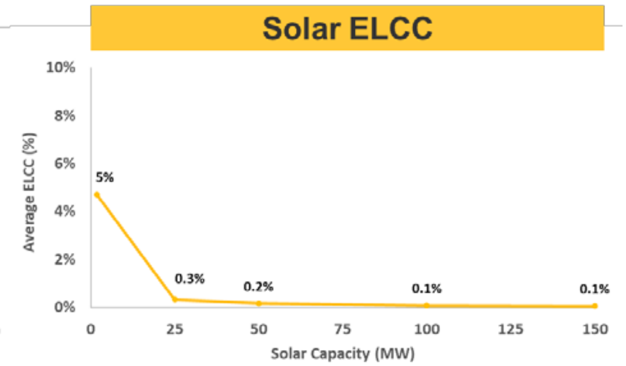
Key Findings

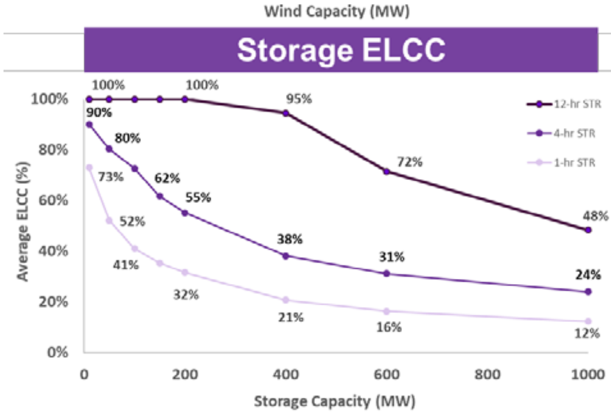
This study finds that in order to meet a 0.1 days/year loss of load expectation (LOLE) target, NSPI should maintain a between a 17.8% -21.0% planning reserve margin (PRM). The range in target PRM is due to a higher and lower estimate of operating reserve requirements for the NSPI system.

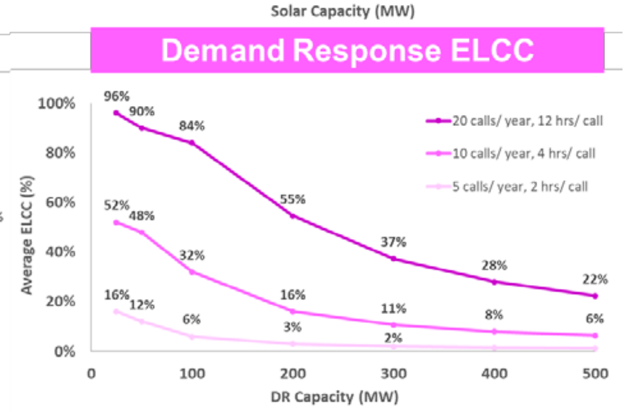
Target PRM
17.8% - 21.0%

This study finds that the dispatch-limited resources wind, solar, storage, and demand response can contribute effective load carrying capability (ELCC) toward meeting the planning reserve margin requirement, but have diminishing returns as additional capacity is added to the system.


Wind ELCC
Average ELCC (%)
50%
40%
30%
20%
10%
0%
38%
34%
31%
30%
22%
19%
14%
0
200
400
600
800
1000
Wind Capacity (MW)


Solar ELCC
Average ELCC (%)
10%
8%
6%
4%
2%
0%
5%
0.3%
0.2%
0.1%
0.1%
0
25
50
75
100
125
150
Solar Capacity (MW)


Storage ELCC
Average ELCC (%)
100%
80%
60%
40%
20%
0%
100%
100%
95%
90%
80%
73%
62%
55%
52%
41%
32%
38%
31%
24%
21%
16%
12%
72%
48%
12-hr STR
4-hr STR
1-hr STR
0
200
400
600
800
1000
Storage Capacity (MW)


Demand Response ELCC
Average ELCC (%)
100%
80%
60%
40%
20%
0%
96%
90%
84%
55%
37%
28%
22%
52%
48%
32%
16%
11%
8%
6%
16%
12%
6%
3%
2%
20 calls/ year, 12 hrs/ call
10 calls/ year, 4 hrs/ call
5 calls/ year, 2 hrs/ call
0
100
200
300
400
500
DR Capacity (MW)

1 Overview

1.1 Purpose of Study

This study provides an update to several important assumptions to be used by Nova Scotia Power Inc. (NSPI) in the integrated resource planning (IRP) process to ensure that NSPI maintains an appropriate level of resource adequacy, so that it can continue to provide reliable and affordable power to its customers. Specifically, this study provides an update of the following planning assumptions:

- Planning Reserve Margin (PRM)
  - The quantity of planning reserves that should be held above the forecasted annual peak load, calculated as a % of annual peak
- Effective Load Carrying Capability (ELCC) of dispatch-limited resources
  - The expected contribution toward the planning reserve requirement from the following dispatch-limited resources
    - Wind
    - Solar
    - Battery Storage
    - Demand Response

1.2 Resource Adequacy and Reliability

Resource adequacy is the ability of an electric power system to serve load across a broad range of weather and system operating conditions, subject to a long-run reliability standard. No electricity system is perfectly reliable as there is always some chance, no matter how small, that generator failures could compound on one another or loads could exceed forecasts with the end result being loss of load. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability such as the variable and intermittent production of renewable resources. Ensuring an appropriate level of resource adequacy is an important goal for utilities seeking to provide both reliable and affordable service to their customers.

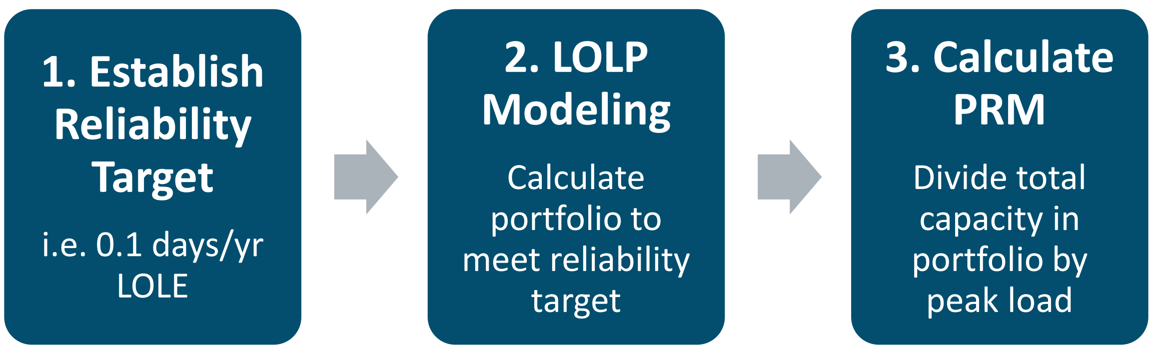
The reliability of a utility can be measured based on frequency, duration, and magnitude of loss of load events which can occur when available generation is insufficient to serve all load plus operating reserve requirements. While utility portfolios are typically designed to meet specified resource adequacy targets, there is no single mandatory or voluntary national standard for resource adequacy. Across North America, resource adequacy standards are established by utilities, regulatory commissions, and regional transmission operators, and each uses its own conventions to do so. The North American Electric Reliability Council (NERC) publishes information about resource adequacy but has no formal governing role. A list of the most common reliability metrics used to assess the resource adequacy of electric power systems is shown in Table 1.

Table 1: Common Reliability Metrics

Acronym	Name	Unit	Definition and Comments
LOLP	**Loss of Load Probability**	**%**	**The probability in a given time period that load + reserves exceeds available generation.** *This metric can be calculated on both a monthly and hourly basis to highlight the times of year when loss of load events are most likely to occur. This metric is also sometimes calculated on an annual basis to assess the overall reliability of the system. While this metric does a good job of capturing the frequency of years that are expected to have loss of load events, it does not capture the duration or magnitude of those events and thus paints an incomplete picture by itself.*
LOLE	**Loss of Load Expectation**	**days/yr**	**The expected average number of days per year where load + reserves exceeds available generating capacity at least once during the day.** *This is the most common metric that is used to evaluate resource adequacy across North America. However, this metric does not capture the magnitude or duration of events (only the frequency) and thus, like other metrics, paints an incomplete picture by itself.*
EUE	**Expected Unserved Energy**	**MWh/yr**	**Average total quantity of unserved energy (MWh) over a year due to load + reserves exceeding available generating capacity.** *This metric captures the total quantity of energy that is expected to be unserved due to loss of load and therefore can capture the impact of large magnitude reliability events since those lead to a large quantity of unserved energy. However, this metric does not capture whether loss of load is concentrated in a small number of large events or a large number of small events and thus needs the other metrics to help paint a complete picture.*
LOLH	**Loss of Load Hours**	**hrs/yr**	**Expected average number of hours per year where load + reserves exceeds available generating capacity.** *This metric capture the total cumulative duration of expected reliability events, but does not capture these events are infrequent with long duration or frequent with short duration nor does it capture the magnitude of these events.*
LOLEV	**Loss of Load Events**	**events/yr**	**Average number of loss of load events per year, of any duration or magnitude, due to load + reserves exceeding available generating capacity.** *This metric captures the frequency of events and is very similar to LOLE but may differ if an there are multiple loss of load events within the same day or if an event lasts overlaps two or more days.*

While a variety of approaches are used, the industry best practice for resource adequacy is to establish a reliability metric and target value and then calculate what quantity of planning reserve are required to achieve that reliability target.

Figure 1: Planning Reserve Margin Calculation Process



These calculations are performed using a class of models known as loss-of-load-probability (LOLP) models that use statistical techniques and/or Monte-Carlo approaches to simulate the capability of an electricity resource portfolio to produce sufficient generation to meet loads across a wide range of different conditions. Once a generation portfolio is established that can meet the reliability target, the resultant planning reserve margin (PRM) is calculated from that portfolio. A PRM establishes a total requirement for capacity based on the peak demand of an electric system plus some reserve margin to account for unexpected outages and extreme conditions.

1.3 Planning Reserve Margin (PRM)

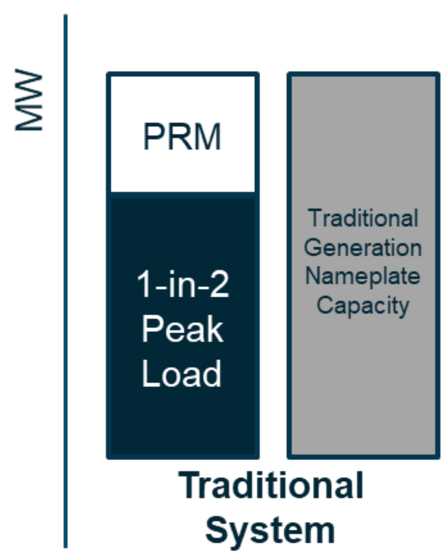
Planning reserves are resources held by the utility above the forecasted peak load that help maintain reliability in the event of:

+ Unplanned forced generator outages
+ Higher than normal peak loads (i.e. very cold weather in Nova Scotia)
+ Operating reserve requirements

The PRM is a convention that is typically based on a comparison of the installed nameplate capacity of traditional generation to the 1-in-2 median peak load. The term “1-in-2” signifies that half of the years are expected to have a peak load higher than this value and half of the years are expected to have a peak load lower than this value. NSPI does not explicitly forecast a 1-in-2 peak load but rather forecasts loads for a winter day with temperatures of -15° C. E3 compared this value across many weather years and found that it reasonably approximated a 1-in-2 peak load event. For this reason, this report uses these peak values interchangeably.

An illustration of the PRM for a generic system is shown in Figure 2.

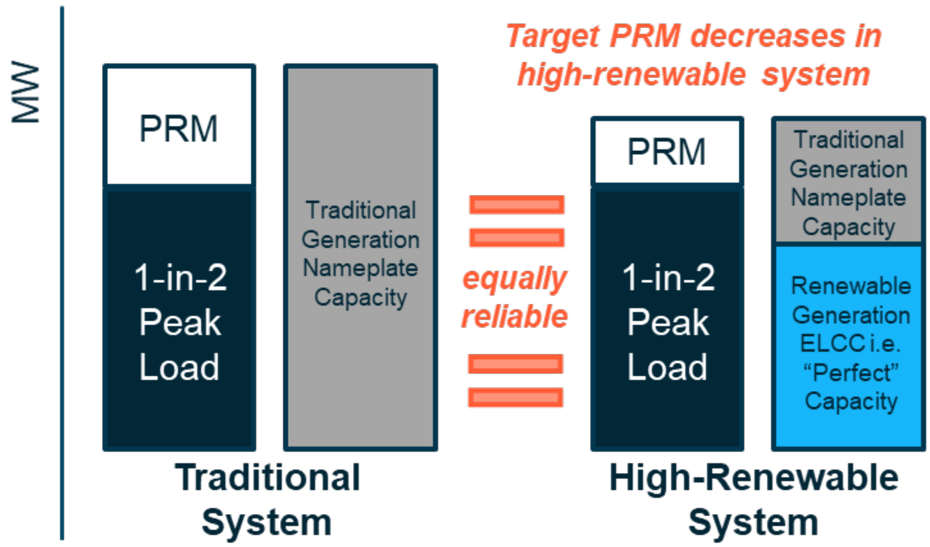
Figure 2: PRM Illustration



Planning reserve margin requirements typically vary among utilities between 12-25+% above peak demand and are highly dependent on system characteristics. For example, larger systems with more load and resource diversity can generally maintain lower PRMs while islanded systems with limited load and resource diversity must maintain higher PRMs to provide the same level of reliability.

To meet this PRM requirement, though DAFOR and scheduled maintenance are modeled for reliability metrics such as LOLE and LOLP, capacity from resources that can produce their full power on demand (e.g., nuclear, coal, oil, gas) are traditionally counted at 100% whereas resources that are constrained in their availability or ability to dispatch on demand for long periods of time (e.g., hydro, storage, wind, solar) are typically de-rated below full capacity. To be clear, fully dispatchable resources with a DAFOR could equivalently be de-rated to account for forced outages but by convention in the electricity sector means this is not generally done. Because variable or dispatch-limited resources are measured in equivalent “perfect” capacity with no forced outages, a system with a significant portion of these resources may actually require a lower planning reserve margin to achieve the same level of reliability as a system with primarily conventional resources. This phenomenon is purely a matter of convention in how these resources are generally counted.

Figure 3: Impact of Variable Resources on Target Planning Reserve Margin



The growing penetration of these variable (e.g., wind and solar) and energy-limited (e.g., hydro, electric energy storage, and demand response) resources increases the importance for the application of sophisticated modeling tools to determine both the appropriate PRM and the contribution of each resource towards resource adequacy.

1.4 Effective Load Carrying Capability (ELCC)

Effective load carrying capability (ELCC) measures the ability of non-firm resources such as wind, solar, storage, hydro, and demand response to contribute to the PRM while still maintaining an equivalent level of system reliability. Equivalently, ELCC is the quantity of "perfect capacity" that could be replaced or avoided with renewables or storage while providing equivalent system reliability. A value of 50% means that the addition of 100 MW of a variable resource could displace the need for 50 MW of firm capacity without compromising reliability.

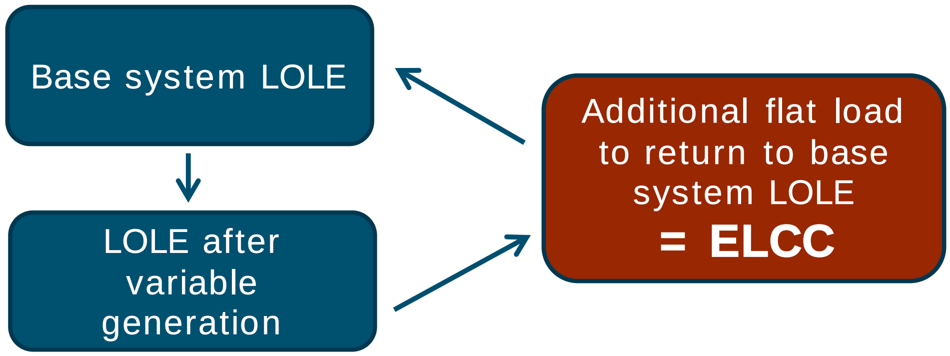
This metric was first introduced in the 1960's as a method of estimating the effect of a change in a conventional unit's capacity or forced outage rate but it has been adapted for evaluating the capacity contribution of variable resources such as wind, solar, and non-dispatchable hydro. ELCC is the most rigorous and accurate measure of a resource's contribution to reliability, but it is also one of the most complex, requiring significant data and computer modeling horsepower. For this reason, many jurisdictions use ELCC approximations such as time window or peak period methods that attempt to estimate the ELCC in a simpler but less accurate manner.

ELCC is calculated via the following procedures, assuming that the utility uses an LOLE reliability standard:

1. Calculate base system LOLE
2. Add variable resource(s) to the system and re-calculate LOLE
    - Due to the new variable resource(s), available generation in each hour is now greater than or equal to the base system which improves reliability (i.e. decreases LOLE)
3. Add flat load (or remove perfect generation) to the system until reliability returns to base system LOLE
    - Adding flat load (i.e. the same quantity of load in each hour) to the system reduces reliability (i.e. increases LOLE)

This process is illustrated in Figure 4.

Figure 4: ELCC Calculation Illustration

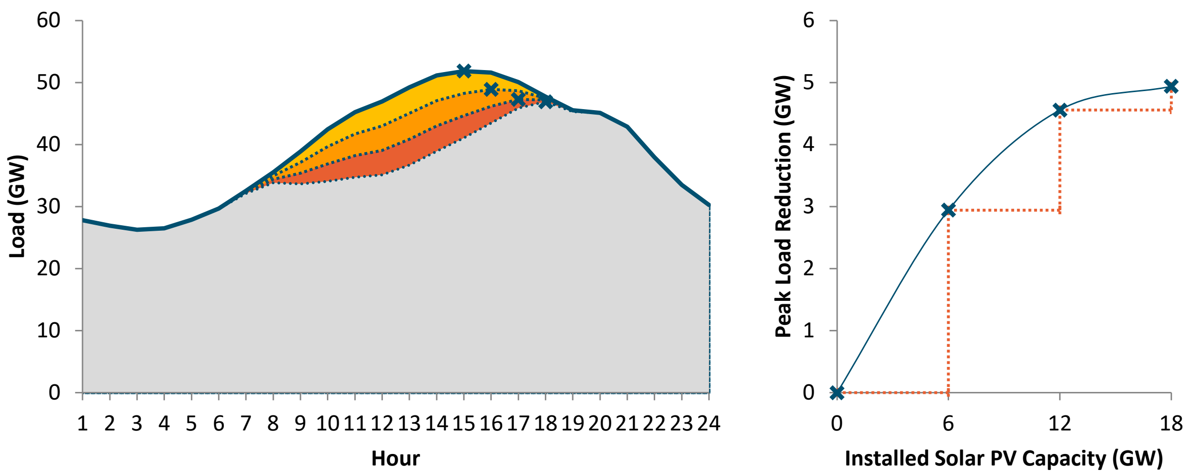


The ELCC of a resource depends on the other resources on the system and underlying load profile which is illustrated through the concept of

+ Diminishing returns
+ Diversity impact

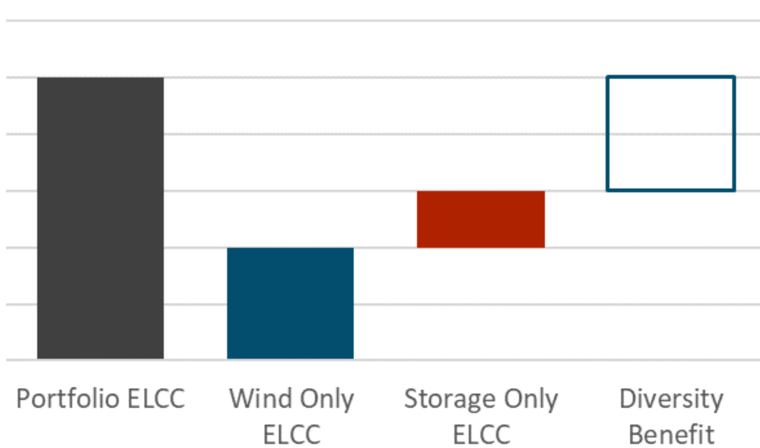
The diminishing marginal peak load impact of solar PV is illustrative of the concept of diminishing returns, although this applies to all variable and energy-limited resources. While the first increment of solar PV has a relatively large impact on peak, it also shifts the "net peak" to a later hour in the day. This shift reduces the coincidence of the solar profile and the net peak such that additional solar resources have a smaller impact on the net peak.

Figure 5: Illustration of Diminishing Marginal ELCC



At the same time as there are diminishing returns for an individual resource, it is also possible that a combination of different resources provides a higher portfolio ELCC than the sum of each individual resource in that portfolio which is illustrated in Figure 6.

Figure 6: Illustration of Diversity Impact on ELCC



This phenomenon is illustrated by pairing wind with energy storage, each providing something the other resource needs. Storage does not produce energy and thus needs a source of energy to provide any ELCC at all. Wind has strong diminishing returns and needs a resource that can shift its production to the highest value hours, i.e. hours with the highest LOLP which are generally the peak net load hours.

1.5 Jurisdictional Review

This report conducts a jurisdictional review of resource adequacy and reliability practices across several key North American and international jurisdictions. Because there is no formal resource adequacy standard set by the North American Electric Reliability Council (NERC), it is beneficial for utilities, regulatory commissions, and regional transmission operators to gather relevant information in the process such as standards in different jurisdictions in the process of determining their own standards and conventions.

Figure 7 shows a map and list of the jurisdictions that are evaluated in this report.

Figure 7: Map of Evaluated Jurisdictions

After review, this report finds that the LOLE with a standard of 1-day-in-10-years is the most common reliability target metric used by the industry, which aligns with Nova Scotia's current reliability target standard. Not all jurisdictions use an LOLE standard and instead use EUE or LOLH for various reasons which are described in more detail in each jurisdiction's subsection. For the jurisdictions with an LOLE reliability standard, achievement of the target reliability standard varies between two primary mechanisms: an explicit PRM and a capacity market.

For jurisdictions with an explicit PRM, either the single vertically integrated utility or broader system operator use LOLP modeling to determine the required PRM to achieve the target LOLE and then assign this PRM to each load serving entity (LSE) within the jurisdiction. Nova Scotia Power fits within this category as a vertically integrated utility. Some integrated system operators (ISOs) such as the

Southwest Power Pool (SPP) also use this method by assigning a calculated PRM to each LSE within their footprint.

A related but different manner that LOLE reliability targets are used is to construct a capacity demand curve in jurisdictions with capacity markets such as PJM, ISONE, and NYISO. In these jurisdictions, an installed capacity quantity is calculated using LOLP modeling for one or more LOLE reliability targets and then is used in conjunction with a supply curve constructed of individual generator bids to determine both a market clearing price for capacity as well as an actual achieved PRM. It is notable in these cases that the achieved PRM may be higher or lower than what is required to achieve the target LOLE, but it can reflect the underlying supply and demand. If there is an excess of capacity, the reliability of the system is better than the target LOLE but the clearing price commensurately falls to reflect the lower value of this incremental reliability contribution.

Table 2 contains a high-level summary of the target reliability metric for each of the evaluated jurisdictions.

Table 2: Jurisdictional Summary of Resource Adequacy Planning

Jurisdiction / Utility	Reliability Metric	Metric Value	Notes
AESO	EUE	800 MWh/year (0.0014%)	AESO monitors capacity and can take action if modeled EUE exceeds threshold; 34% PRM achieved in 2017 w/o imports
CAISO	PRM	15%	No explicit reliability standard
ERCOT	N/A	N/A	Tracks PRM for information purposes; “Purely information” PRM of 13.75% achieves 0.1 events/yr; Economically optimal = 9.0%; Market equilibrium = 10.25%
Florida	LOLE	0.1 days/year	15% PRM required in addition to ensuring LOLE is met
ISO-NE	LOLE	0.2/0.1/0.01 days/year	Multiple LOLE targets are used to establish demand curve for capacity market
MISO	LOLE	0.1 days/year	7.9% UCAP PRM; 16.8% ICAP PRM
Nova Scotia	LOLE	0.1 days/year	20% PRM to meet 0.1 LOLE standard

NYISO	LOLE	0.1 days/year	LOLE is used to set capacity market demand curve; Minimum Installed Reserve Margin (IRM) is 16.8%; Achieved IRM in 2019 is 27.0%
PacifiCorp	N/A	N/A	13% PRM selected by balancing cost and reliability; Meets 0.1 LOLE
Hawaii (Oahu)	LOLE	0.22 days/yr	Relatively small system size and no interconnection results in 45% PRM
PJM	LOLE	0.1 days/year	LOLE used to set target IRM (16%) which is used in capacity market demand curve
SPP	LOLE	0.1 days/year	PRM assigned to all LSE's to achieve LOLE target: 12% Non-coincident PRM & 16% Coincident PRM
Australia	EUE	0.002%	System operator monitors forecasted reliability and can intervene in market if necessary
Great Britain	LOLH	3 hours/year	5% (Target PRM 2021/22) 11.7% (Observed PRM 2018/19)
Ireland	LOLH	8 hours/year	LOLH determines total capacity requirement (10% PRM) which is used to determine total payments to generators (Net-CONE * PRM)

For each jurisdiction that relies on a PRM as an intermediate step in the resource adequacy planning process, they must determine what the contribution of each resource is toward that PRM requirement. In most jurisdictions, dispatchable generation (nuclear, coal, oil, gas) is counted at its nameplate capacity, although some jurisdictions such as NYISO explicitly take into account a resource's forced outage rate in determining their contribution. For dispatch-limited resources (wind, solar, storage, hydro, demand-side), the approach varies much more widely across jurisdictions. Most still utilize a "rule of thumb" approach to counting these resources which tends to have limited impact given that these resources still comprise a relatively small percentage of total capacity in most jurisdictions. However, many system operators are currently working on efforts to increase the sophistication in how they approach these issues as the quantity of these dispatch-limited resources continues to grow.

Each jurisdiction's approach to counting the contribution of dispatch-limited resources toward the PRM and more detail on reliability metrics and planning processes are included the following sections.

1.5.1 SOUTHWEST POWER POOL (SPP)

The Southwest Power Pool (SPP) is an ISO covering multiple states in the middle of the U.S. including all or portions of Oklahoma, Arkansas, Texas, Kansas, Missouri, Nebraska, South Dakota, North Dakota, and Montana. SPP uses a target reliability metric of 0.1 days/yr LOLE and models to derive a PRM that is required to meet the 0.1 LOLE target. They assign a non-coincident PRM to each load responsible entity in the ISO which in aggregate will achieve the coincident target PRM. Each load responsible entity must procure capacity resources to meet their non-coincident PRM assignment which currently stands at 12.0% for general entities and 9.8% for hydro-based entities. These values are updated every two years. Net capability is used in PRM accounting for dispatchable resources and a heuristic top load hour methodology is used to determine the capacity credit for wind and solar toward meeting the PRM.

1.5.2 MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO)

The Midcontinent Independent System Operator (MISO) is an ISO covering multiple states in the middle of the U.S. including all or portions of Louisiana, Arkansas, Mississippi, Missouri, Indiana, Illinois, Kentucky, Iowa, South Dakota, North Dakota, Montana, Minnesota, Wisconsin, and Michigan. MISO uses a target reliability metric of 0.1 days/yr LOLE and calculate a PRM using models to derive a PRM that is allocated proportionally to each load serving entity's coincident peak. This is process is updated annually. The current PRM is 16.8% for installed capacity and 7.9% after accounting for the forced outages of dispatchable generation. Renewable credit is established by an ELCC study and currently stands at 15.2% for wind and 50% for solar.

1.5.3 ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT)

The Electric Reliability Council of Texas (ERCOT) is a system operator located wholly within the state of Texas. ERCOT is a deregulated electricity market with an “energy-only” framework and does not have an explicit reliability target or planning reserve margin. ERCOT periodically studies reliability and calculates an expected market equilibrium reserve margin (currently 10.25%) that they expect to achieve through the economics of their energy-only compensation framework as well as an economically optimal reserve margin (currently 9%) based on the cost of new capacity and the value of lost load. They also calculate a “purely informational” PRM that would be required to achieve an LOLEV of 0.1 events/year. However, none of these metrics have any impact on the actual achieved PRM, although theoretically regulators could intervene if a study determined that the energy-only framework was not going to yield and acceptable level of reliability.

1.5.4 NEW YORK INDEPENDENT SYSTEM OPERATOR (NYISO)

The New York Independent System Operator (NYISO) is an ISO located wholly within the state of New York. NYISO uses a target reliability metric of 0.1 days/year LOLE to determine a minimum installed reserve margin (IRM) as an input into a demand curve used in a capacity market. Their demand curve is constructed such that the achieved IRM exceeds the minimum IRM in most cases. The minimum IRM in 2018 was 16.8% and the achieved IRM was 27%. These targets are updated annually and are used in conjunction with local capacity requirements (LCRs) for different zones. Renewables are de-rated using heuristics for contribution to the IRM and these values differ for winter and summer.

1.5.5 NEW ENGLAND INDEPENDENT SYSTEM OPERATOR (ISO-NE)

The New England Independent System Operator (ISO-NE) is an ISO operating in the Northeast U.S. and covers all or parts of Massachusetts, Rhode Island, Connecticut, Vermont, New Hampshire, and Maine. ISONE uses a set of three LOLE targets (0.2, 0.1, and 0.01 days/year) in their resource adequacy planning. Using LOLP modeling, a reserve margin is calculated for each point (currently 13.1%, 16.8%, and 26.1%) which is used to construct a demand curve to determine a market clearing price and total capacity. These values are updated annually. Wind and solar qualifying capacity are performance based and counted at the resource’s median output during the “reliability hours” over the previous 5 years.

1.5.6 HAWAIIAN ELECTRIC (OAHU)

Hawaiian Electric is an investor owned utility that serves multiple Hawaiian islands, including Oahu. Due to the relatively small size of the electric sector on Oahu along with no electrical interconnections to other jurisdictions, Oahu maintains a 45% planning reserve margin in order to meet a 0.22 days/year LOLE standard.

1.5.7 PJM

PJM is the largest ISO in the U.S. and covers multiple states in the mid-Atlantic region of the U.S. including Pennsylvania, New Jersey, Maryland, Delaware, Virginia, North Carolina, West Virginia, Kentucky, Ohio, Indiana, Michigan, and Illinois. PJM uses a reliability planning target of 0.1 days/year LOLE and calculates an installed reserve margin (IRM) required to meet this target. The IRM is used as an input into a capacity auction demand curve and currently stands at 16.0% for 2019/2020. This value is updated annually and includes locational deliverability areas (LDAs). Renewables' contribution to the IRM is calculated using a heuristic capacity credit method.

1.5.8 CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO)

The California Independent System Operator (CAISO) is an ISO located wholly within the state of California. The CAISO currently does not have an explicit reliability standard but does have a 15% PRM that is applied on a monthly basis and implemented via the California Public Utilities Commission (CPUC). Load serving entities (LSEs) are responsible for procuring monthly capacity resources to satisfy their 15% PRM and must meet not only system but also local and flexible resource requirements. Renewables are counted toward the PRM using an ELCC methodology that is implemented by the CPUC.

1.5.9 ALBERTA ELECTRIC SYSTEM OPERATOR (AESO)

The Alberta Electric System Operator (AESO) is an ISO located in Alberta, Canada. The AESO uses an EUE reliability planning target of 800 MWh/yr which is 0.0014% of annual load. The AESO does not currently have an explicit PRM or capacity market (although planning for a capacity market is currently underway). Instead the AESO publishes quarterly reports monitoring the existing and forecasted reliability of the system and can take actions if the EUE grows above the threshold metric. In 2017, the achieved reserve margin was 34% without interties and 44% with interties.

1.5.10 PACIFICORP

PacifiCorp is a vertically integrated utility operating primarily in Oregon and Utah but with small segments of load in California, Washington, Idaho, and Montana. PacifiCorp is not part of an ISO and is responsible for their own resource adequacy planning and system operation. They do not use an explicit planning standard but calculate multiple metrics. In their 2017 IRP, they selected a PRM of 13% which was based on a combination of reliability, cost, and risk. This value is updated every 2 years. PacifiCorp is able to maintain a PRM on the low end of the most similar utilities due to their significant interconnection ties with other entities in the Pacific Northwest.

1.5.11 AUSTRALIA

The Australian Energy Market Operator (AEMO) uses an EUE reliability target metric of 0.002% of total energy demand. This standard is set based on an economically optimal value but is not associated with an explicit reserve margin requirement. The AEMO forecasts EUE and can intervene in the market by procuring additional generator capability if necessary.

1.5.12 GREAT BRITAIN

Great Britain uses an LOLH reliability target of 3 hours/year which is based on an economic optimum. There is no explicit PRM requirement but the capacity margin is monitored and the utility can intervene to add capacity if the LOLH is expected to rise above the acceptable threshold.

1.5.13 REPUBLIC OF IRELAND

The Republic of Ireland uses an LOLH reliability target of 8 hours/year which is based on an economic optimum. This LOLH standard is used to determine a MW capacity requirement which is in turn used to determine capacity payments to generators such that the net cost of new entry (net-CONE) multiplied by the capacity requirement determines the total quantity of capacity payments that are divided among all generators. Generators are paid based on their de-rated capacity to account for forced outages and renewable units are subject to de-rating factors to account for their limited availability (Wind = 10.3% and Solar = 5.5%)

1.6 Resource Adequacy in Nova Scotia

Nova Scotia is a member of the Northeast Power Coordinating Council (NPCC) which is one of the nine regional electric reliability councils under the North American Electric Reliability Corporation (NERC). The NPCC establishes a set of reliability criteria that are then approved by the Nova Scotia Utility and Review Board (NSUARB). These criteria state that each resource planner, of which NSPI is one, shall demonstrate an LOLE of 0.1 days/year. This standard of 0.1 days/year LOLE is in-line with resource adequacy best practices planning as demonstrated in Section 1.5. Every few years (most recently in 2014), NSPI performs an LOLE study to calculate the PRM required to achieve a 0.1 LOLE standard. In 2014, the result of this study confirmed the 20% PRM that had been in place historically for NSPI.

As described in Section 1.1, this study provides an update of the required PRM and confirms that a PRM of at least 20% is necessary to meet a target LOLE of 0.1 days/year.

As a vertically integrated utility, NSPI is responsible for creating an IRP that meets all system needs, including the PRM, and submitting this plan to the UARB. Just as with other jurisdictions as described in previous sections, there are many reasons why the achieved PRM may differ from the target PRM. In particular in the case of NSPI, investments in capacity tend to be much lumpier than changes in annual peak load and so it may be economically optimal to build/contract/maintain capacity in exceedance of the 20% PRM in order to ensure future capacity is available economically.

This study uses a 0.1 days/year LOLE standard, consistent with NPCC criteria and previous NSPI planning standards. This study calculates the target PRM that is required to achieve a 0.1 LOLE.

2 RECAP Overview and Methodology

2.1 Model Overview

This study assesses the resource adequacy the Nova Scotia Power Inc. (NSPI) system using E3's Renewable Energy Capacity Planning (RECAP) model. RECAP is a loss-of-load-probability model developed by E3 that has been used extensively to test the resource adequacy of electric systems across the North American continent, including California, Hawaii, Canada, the Pacific Northwest, the Upper Midwest, Texas, and Florida.

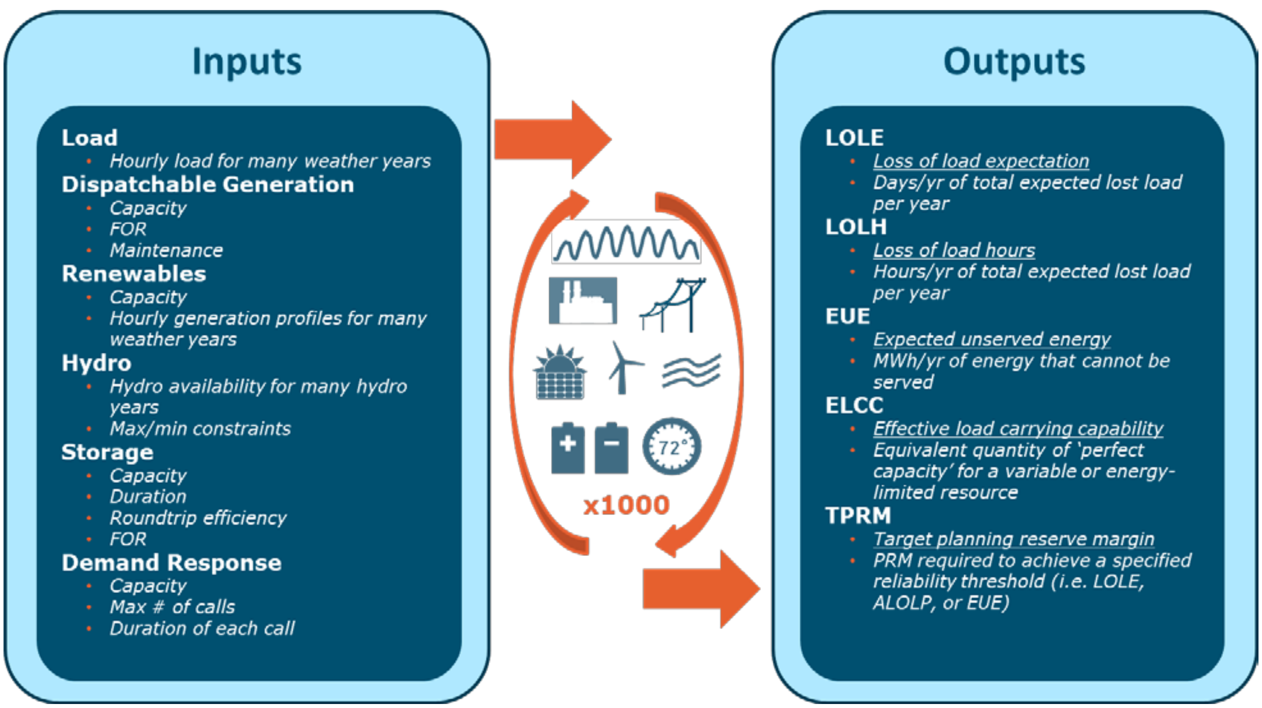
RECAP was developed specifically to address the needs of a changing electricity sector by incorporating the unique characteristics of dispatch-limited resources such as wind, solar, hydro, battery storage, and demand response into the traditional reliability framework. RECAP produces a number of metrics directly useful to utilities in planning including the following listed in Table 3. For more information on reliability metrics and their definitions, see Section ▯.

Table 3: Example RECAP Outputs

Category	Metric	Units
Reliability Metrics	LOLE	Days/year
	LOLH	Hours/year
	LOLEV	Events/year
	EUE	MWh/year
	LOLP	%
PRM Metrics	Target PRM	%
	Achieved PRM	%
ELCC	ELCC	% or MW

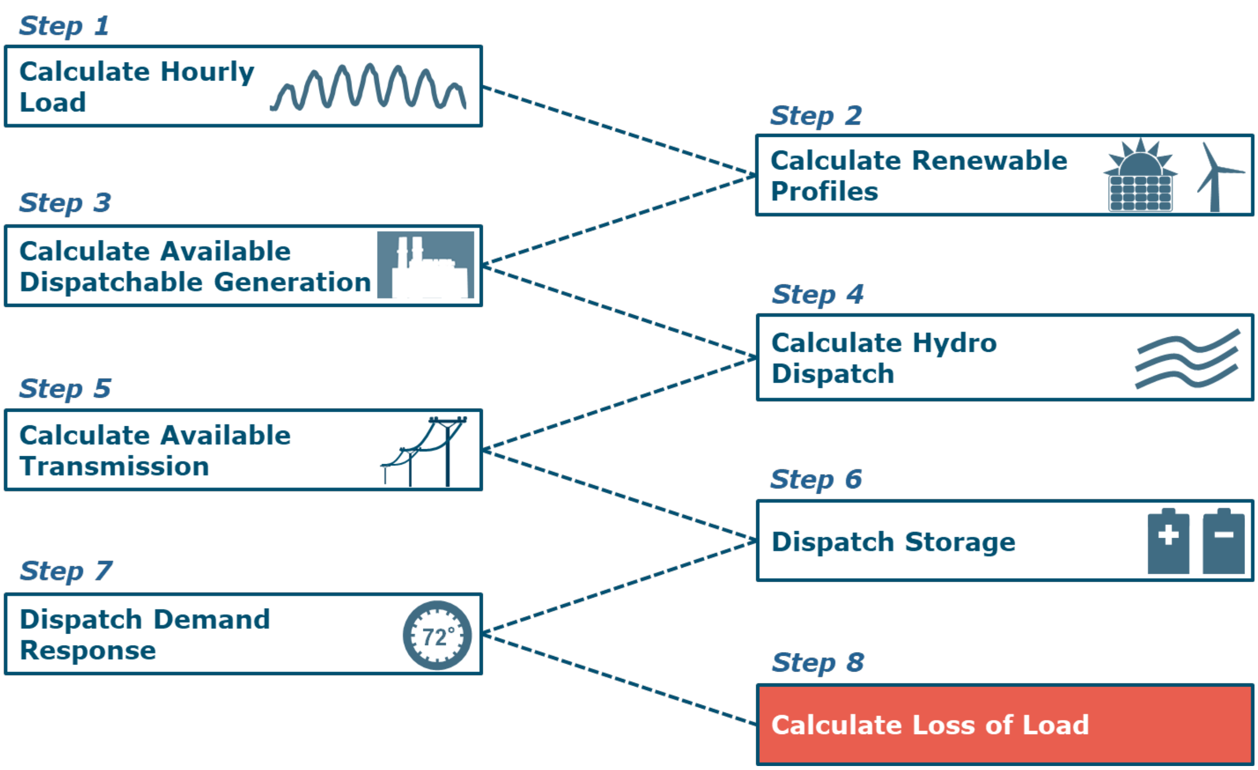
RECAP calculates these metrics through by simulating the electric system with a specific set of generating resources and loads under a wide variety of weather years, renewable generation years, and stochastic forced outages of electric generation resources and imports on transmission. Correlations enforced within the model capture linkage among load, weather, and renewable generation conditions. Time-sequential simulation tracks the state of charge and energy availability for dispatch-limited resources such as hydro, energy storage, and demand response. By simulating the system thousands of times with different combinations of these factors, RECAP provides robust, stochastic estimation of LOLE, target PRM, and other reliability statistics. Figure 8 provides an overview of this process.

Figure 8: RECAP Model Overview



RECAP conducts a Monte-Carlo time-sequential simulation of loads and resource availability, and the general steps in RECAP's algorithm are shown in Figure 9.

Figure 9: RECAP Model Steps



In order to perform each step in the model listed above, RECAP requires data on the characteristics of loads and the resources available to serve those loads which are listed in Table 4.

Table 4: RECAP Data Requirements

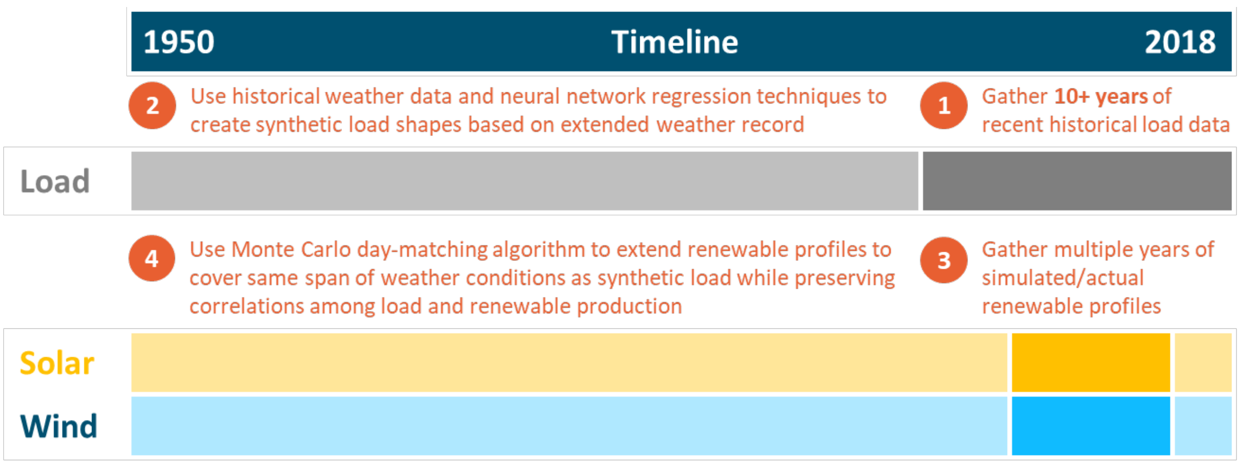
Category	Metric	
Load	Historical hourly load for many (10+) years	
	Operating reserve requirements	
Weather	Historical temperature data (daily max/min) for many (50+) years	
Dispatchable Generation	Net dependable capacity	
	Forced outage rate (FOR)	Mean time to failure (MTTF)
		Mean time to repair (MTTR)
	Maintenance schedules	
Renewable Generation	Nameplate capacity	
	Historical hourly generation profiles for as many years as possible	
	Historical wind speed or solar insolation data for potential new renewable generation sites	
Hydro Generation	Daily MWh availability	
	Maximum output & sustained peaking limits	
	Minimum output	
Energy Storage	Nameplate capacity (charge & discharge)	
	Roundtrip efficiency	
	Duration (hrs)	
	Forced outage rate (FOR)	
Demand Response	Maximum capacity	
	Maximum # of calls per week/month/year	
	Maximum duration of each call	
Transmission	Zonal representation of electric system	
	Maximum transmission capacity between zones	
	Forced outage rates (FOR) of transmission lines between zones	

A more detailed description of the different steps of the model and how the data is used is described in Section 2.2.

2.2 Detailed Model Methodology

RECAP is a time-sequential model that simulates the electric power system across a series of many years using historical weather data and plausibly extending loads and renewable resources across same time horizon. The major steps of this process are illustrated in Figure 10 and are discussed in more detail below.

Figure 10: Process to Extend Load and Renewable Profiles



2.2.1 LOAD SHAPE DEVELOPMENT

Developing a robust set of hourly load profiles that is representative of a broad distribution of possible weather conditions – particularly extreme events that are often correlated with higher risk of loss of load – is a challenge for reliability modelers, as actual load shapes from recent historical years may not be representative of the long-run distribution of such extreme weather events.

To overcome this challenge, E3 develops a neural network regression using actual hourly loads from recent historical years (5-10 years) and a longer record of key weather indicators and date information (30-60 years) to develop a library of hourly load profiles that represent how today's electric demands would behave under a wide range of plausible weather conditions. This method allows E3 to capture the variability of load across very long time horizons (i.e., 1-in-2, 1-in-10, 1-in-50 year events, etc.).

E3 uses the following independent variables in the neural network regression approach

+ Max and min daily temperature (including one and two-day lag)
+ Month (+/- 15 calendar days)
+ Day-type (weekday/weekend/holiday)
+ Day index for economic growth or other linear factor over the recent set of load data

E3 performs this analysis using daily load totals by summing hourly load for each hour of the day. Once daily load totals have been predicted for historical weather days using the neural network process, E3 converts these totals back into hourly load profiles by finding a load profile within the actual historical record with the same day-type (weekday/weekend/holiday), is within +/- 15 calendar days, and has the closest total daily load.

An example result of this neural network process is shown in Figure 11.

Figure 11: Example Backcast of Hourly Load Data

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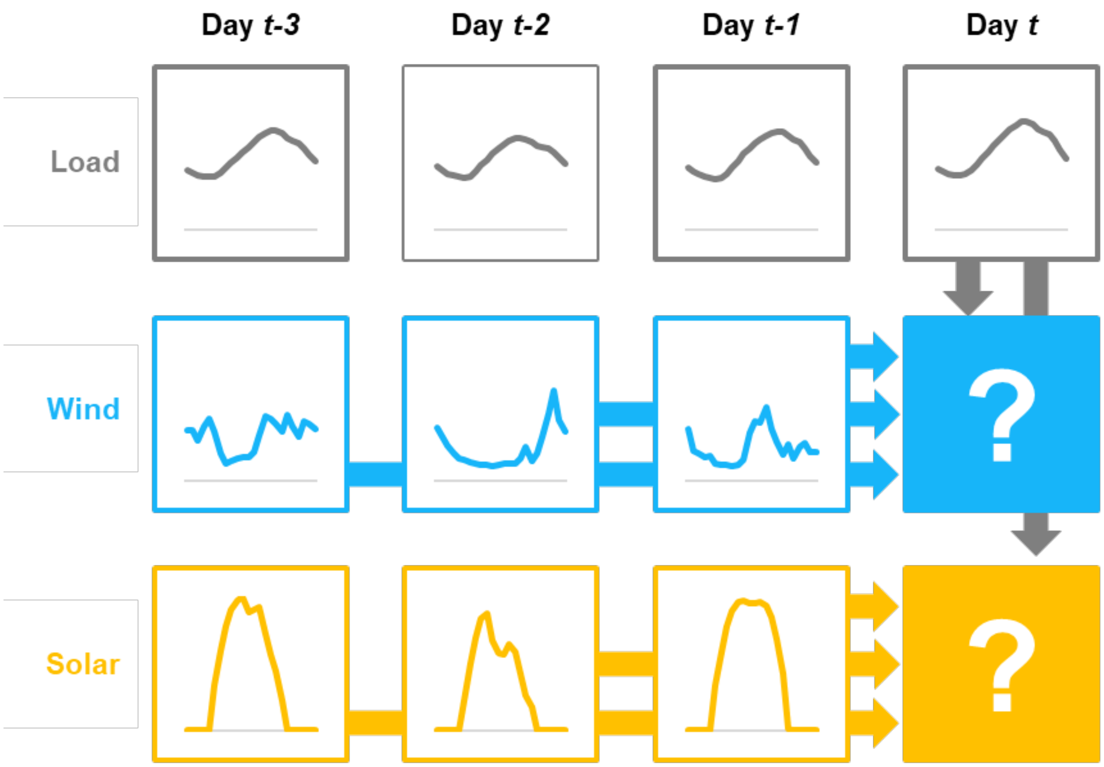
Using a very large starting data set of hourly loads helps to put load uncertainty into context in terms of how often certain events will occur. Reliability events in high-renewable systems tend to be less driven by peak load events, but rather by sustained multi-day periods of high loads and corresponding low renewable generation.

2.2.2 RENEWABLE PROFILE DEVELOPMENT

Because renewable generation data is usually only available for a handful of recent years, E3 uses a Monte-Carlo approach to extend the data to cover the entire weather record for which load shapes are available while preserving correlations between load and renewable production. The model chronologically selects daily wind and solar profiles for each day on a rolling basis using a day matching algorithm that considers both the daily load and the level of wind/solar generation in the preceding days, with the most recent days being weighted the most highly.

Figure 12: Schematic Representation of Algorithm Used to Create Synthetic Load-Renewable Pairings



In order to choose a renewable profile for a specific day of interest (day *t*), the model searches through the actual record of time-synchronous historical load and renewable profiles to find days similar to day *t*. For each day *i* in the true historical record, RECAP evaluates a similarity rating based on multiple criteria, including the load on that day and renewable generation on preceding days. The similarity rating is calculated as shown below.

$$Similarity\ Rating_i = w_L \frac{|L_t - L_i|}{\sigma_L} + w_{R1} \frac{|R_{t-1} - R_{i-1}|}{\sigma_R} + \cdots + w_{Rn} \frac{|R_{t-n} - R_{i-n}|}{\sigma_R}$$

Once the similarity has been determined between each day, a daily renewable profile for each class of renewable resources is stochastically selected based on the similarity rating, with higher similarity days having a higher chance of being selected. There are multiple probability functions that the model can use in this step, and the function that E3 used in this analysis is shown below.

$$\Pr(target = i) = \frac{e^{-\left(\frac{similarity_i}{\sigma}\right)^2}}{\sum_{j=1}^{n} e^{-\left(\frac{similarity_j}{\sigma}\right)^2}}$$

This step ensures preservation of both the correlation between load and renewable generation and the autocorrelation of the renewable generation profile itself. For example, winter storms tend to last for multiple days which means that a windy or still day is more likely to be followed by a windy or still day which is captured in this approach. Other correlations are also captured that are dependent upon the specific system in question. An illustration of the correlations that are still captured as the model extends the wind/solar record is shown below.

Figure 13: Maintenance of Correlations Between Load and Renewable Production in RECAP's Day-Matching Algorithm

Time-Synchronous Load & Renewable Profiles

Load Factor (% of 1-in-2 Peak)	Wind Capacity Factor (% of Nameplate)									
	0-10%	10-20%	20-30%	30-40%	40-50%	50-60%	60-70%	70-80%	80-90%	90-100%
30-40%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
40-50%	3.3%	4.3%	4.7%	4.6%	4.1%	2.9%	2.2%	1.2%	0.4%	0.1%
50-60%	5.9%	6.6%	6.6%	6.3%	5.6%	4.1%	3.2%	2.2%	1.0%	0.3%
60-70%	3.3%	3.1%	3.0%	3.2%	2.7%	2.1%	1.6%	0.8%	0.3%	0.0%
70-80%	1.1%	1.0%	1.0%	1.1%	1.0%	0.8%	0.4%	0.1%	0.0%	0.0%
80-90%	0.4%	0.4%	0.5%	0.5%	0.5%	0.3%	0.1%	0.0%	0.0%	0.0%
90-100%	0.1%	0.2%	0.3%	0.2%	0.1%	[illegible]	0.0%	0.0%	0.0%	0.0%
100-110%	0.0%	0.0%	0.0%	0.0%	0.0%	[illegible]	0.0%	0.0%	0.0%	0.0%

RECAP Synthetic Load & Renewable Profiles

Load Factor (% of 1-in-2 Peak)	Wind Capacity Factor (% of Nameplate)									
	0-10%	10-20%	20-30%	30-40%	40-50%	50-60%	60-70%	70-80%	80-90%	90-100%
30-40%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
40-50%	3.5%	4.7%	5.2%	5.2%	4.4%	3.2%	2.3%	1.4%	0.5%	0.1%
50-60%	5.9%	6.5%	6.5%	6.4%	5.4%	4.2%	3.4%	2.3%	1.1%	0.3%
60-70%	2.9%	2.7%	2.5%	2.8%	2.5%	2.0%	1.5%	0.8%	0.3%	0.1%
70-80%	0.8%	0.8%	0.8%	1.0%	1.0%	0.8%	0.4%	0.1%	0.0%	0.0%
80-90%	0.2%	0.3%	0.4%	0.4%	0.4%	0.3%	0.1%	0.0%	0.0%	0.0%
90-100%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
100-110%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

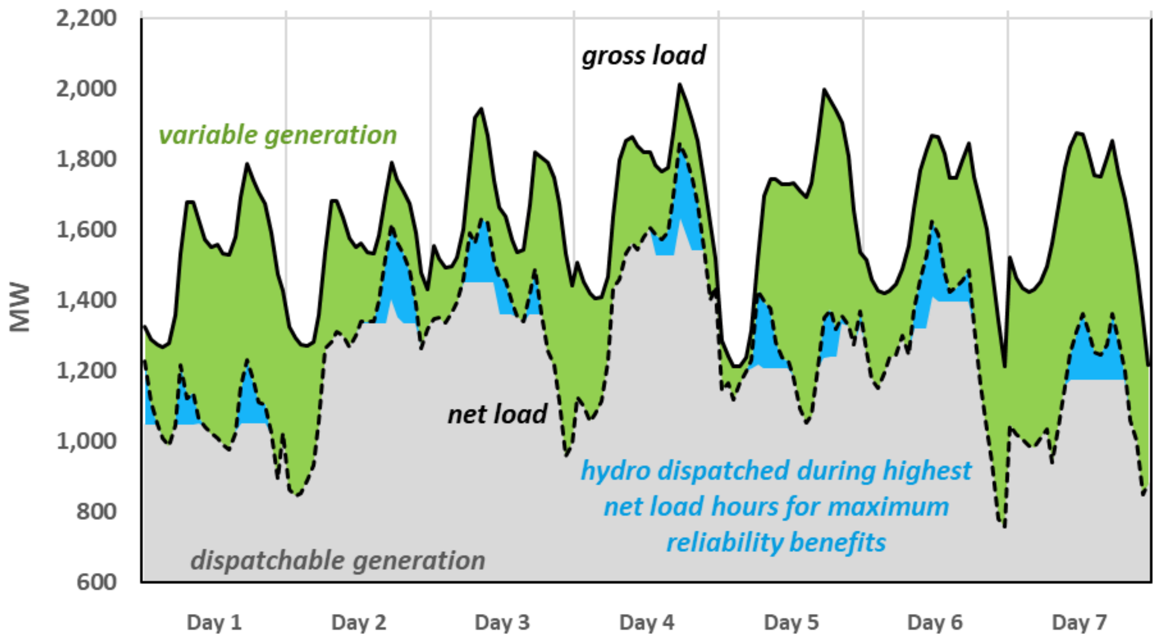
RECAP's day-matching algorithm captures key correlations between load and renewable production, including (1) tendency of wind to produce at low levels of output during very high load events, and (2) low loads during periods of high wind output

2.2.3 HYDRO DISPATCH

Hydro can be modeled using a variety of approaches in RECAP. For hydro resources that can be dispatched by the system operator without any substantial limits to maximum time limits (e.g. 1 week or more), E3 generally models these resources equivalently to firm dispatchable resources such as nuclear, coal, oil, and gas. For hydro resources that have limited dispatchability, such as run-of-river hydro units with no pondage, E3 generally models these resources equivalently to variable resources such as wind and solar. In this project, tidal was modeled as a variable resource similar to wind and solar. For other hydro resources, E3 models generation using available historical hydro generation which captures the annual variability in hydro generation due to differences in precipitation. RECAP dispatches water within a day, week, month, or other defined time period to maximize reliability, subject to operating characteristics such as min output, max output, and/or sustained peaking limits. In this project, daily hydro budgets that vary by month are used. A correlation between hydro and load/renewables is not imposed due to the large disconnect in fundamental drivers. For example, hydro availability in May is usually driven by snowpack melt of precipitation that would have fallen throughout the previous winter which is tenuously correlated with the cloud cover that drives solar generation in May.

In this project, only the Wreck Cove resource was determined to fit the criteria for inclusion with this dispatchable hydro category. In order to maximize the reliability value of a hydro resource with limited daily energy generation, Wreck Cove is dispatched into the highest net load hours, subject to maximum output constraints (minimum output is 0 MW). Figure 14 shows Wreck Cove dispatch in the RECAP model during a sample winter week.

Figure 14: RECAP Sample Hydro Dispatch During Winter Week



2.2.4 DISPATCHABLE GENERATION AVAILABILITY AND TRANSMISSION

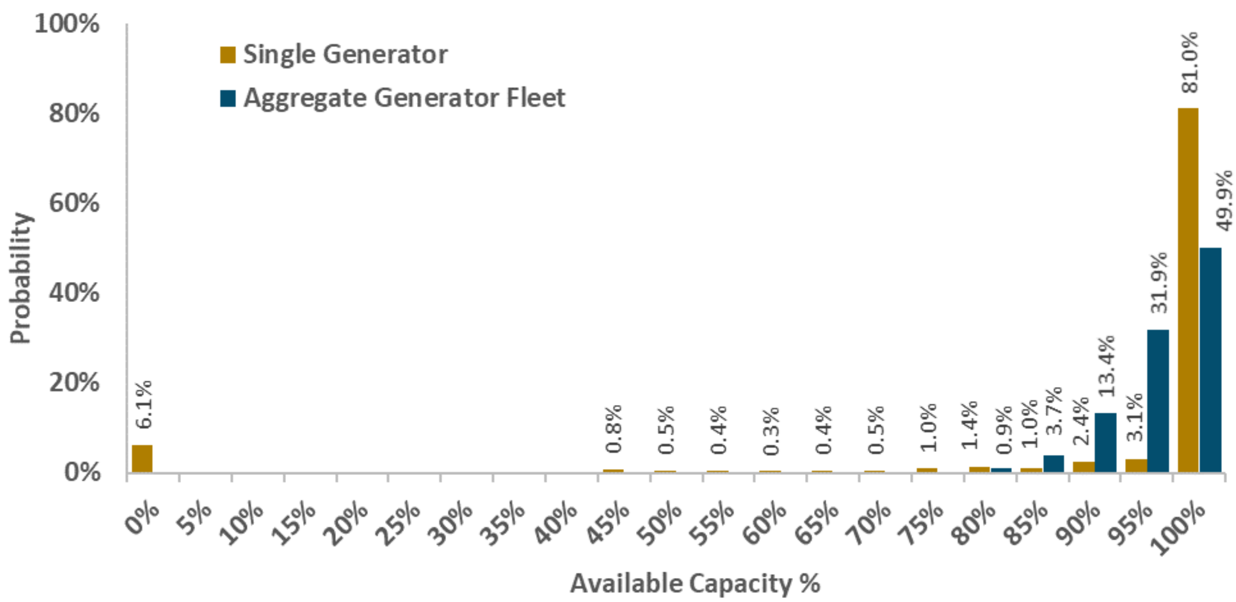
RECAP creates a time series of available dispatchable generation and transmission by stochastically introducing forced outages that are consistent with an individual resource's forced outage rate (FOR), mean time to failure (MTTF), and mean time to repair (MTTR). Similarly, resources can be de-rated for maintenance based on user input monthly schedules. Resources are assumed to be available to produce energy at their net dependable capacity unless they are experiencing a forced outage (full or partial) or a maintenance event. RECAP produces a time series of total aggregate dispatchable generator and transmission availability for the entire time series by aggregating individual generator availability. This process is illustrated in Figure 15 for four sample dispatchable generators over ten sample hours.

Figure 15: Illustrative Dispatchable Generator Availability Table

Hourly Availability	1	2	3	4	5	6	7	8	9	10
Generator 1	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Generator 2	100%	100%	100%	100%	0%	0%	0%	0%	100%	100%
Generator 3	100%	100%	50%	50%	50%	100%	100%	100%	100%	100%
Generator 4	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Total	**100%**	**100%**	**88%**	**88%**	**63%**	**75%**	**75%**	**75%**	**100%**	**100%**

Figure 16 illustratively shows the aggregated output of all generators after introducing individual outages and aggregating across the entire time series. While an individual generator has a 6.1% probability of experiencing a full forced outage, the aggregate dispatchable generator availability never drops below 80% and has nearly a 95% probability of being higher than 90% available.

Figure 16: Aggregate Illustrative Dispatchable Generator Availability Distribution



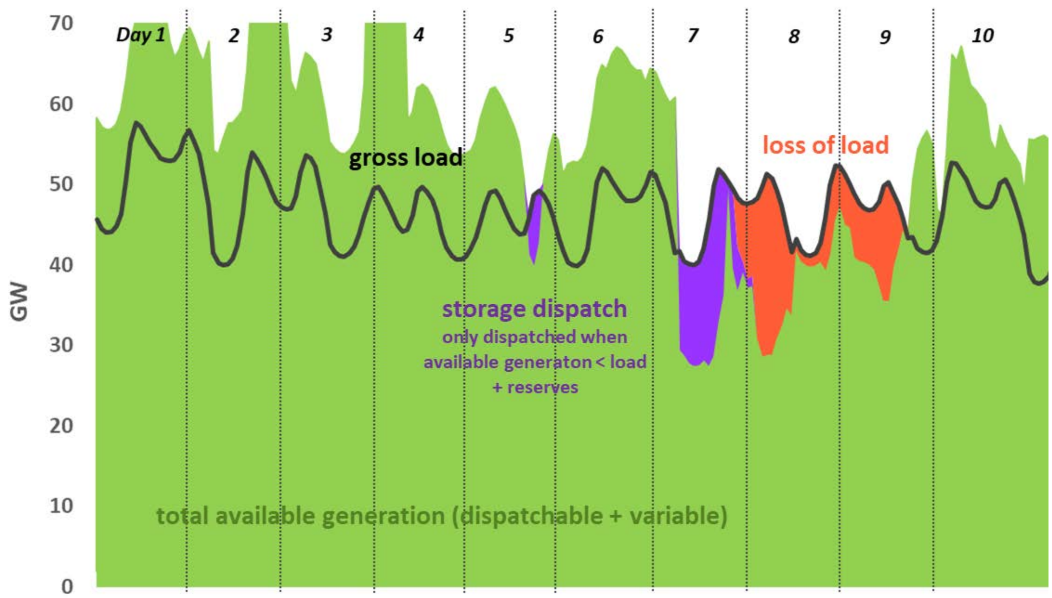
2.2.5 STORAGE AND DEMAND RESPONSE

Storage and demand response resources are dispatched time-sequentially in RECAP over the entire time horizon in order to accurately capture the energy limitations these resources have in terms of the duration and frequency with which they can provide energy to the electricity system.

Storage is dispatched in RECAP for the purposes of reliability such that it only discharges energy to avoid or mitigate a potential loss of load event after all other resources have been utilized. Conversely, storage will charge from any available resource if its state of charge is less than 100% and there is available generation in the electricity system that is not being used to serve load or provide operating reserves. While this mode of storage operation may not be how storage is predominantly used on a day-to-day basis for economics, it is represented in the model this way under the assumption that the system operator will likely have sufficient foresight into a potential reliability event (e.g. weather forecast of very hot/cold weather) and will modify the charge and discharge schedule in order to ensure maximum reliability value from the storage resource. Storage is modeled using a roundtrip efficiency factor and a forced outage rate if available.

A sample week of illustrative storage operation using this approach is shown in Figure 17.

Figure 17: Example Storage Dispatch During Sample Week



After storage has been dispatched, demand response is dispatched if load + operating reserves still exceeds available generation. Demand response is utilized as the resource of last resort given the general manner that this resource is structured through programs that limit the number of times it can be called over a defined time period. For example, a demand response programs may sign up customers with the promise that they will only need to curtail their load up to 10 times for year. RECAP models demand response with both limits on the number of times that a resource can be called in a given time period and a maximum duration of a response when a customer responds to a call.

2.2.6 MODEL OUTPUTS

After all resources have been dispatched in the model for load plus operating reserves, the model aggregates that remaining loss of load events to calculate various reliability statistics for the system including LOLE, LOLH, LOLEV, and EUE. To calculate the target PRM, the model assesses whether the achieved reliability of the system for a specific metric (for example, LOLE) is greater or less than the target metric (for example, 0.1 LOLE) and then uses a Newton method algorithm to add or remove firm capacity from the system in order to achieve the target level of reliability. Once the system has reached target reliability, the model calculates the capacity contribution from each resource and divides by the 1-in-2 median annual peak load in order to calculate the achieved PRM. For dispatchable resources, the net dependable capacity is used for the capacity contribution and for variable, hydro, storage, and demand response resources, the ELCC method is used.

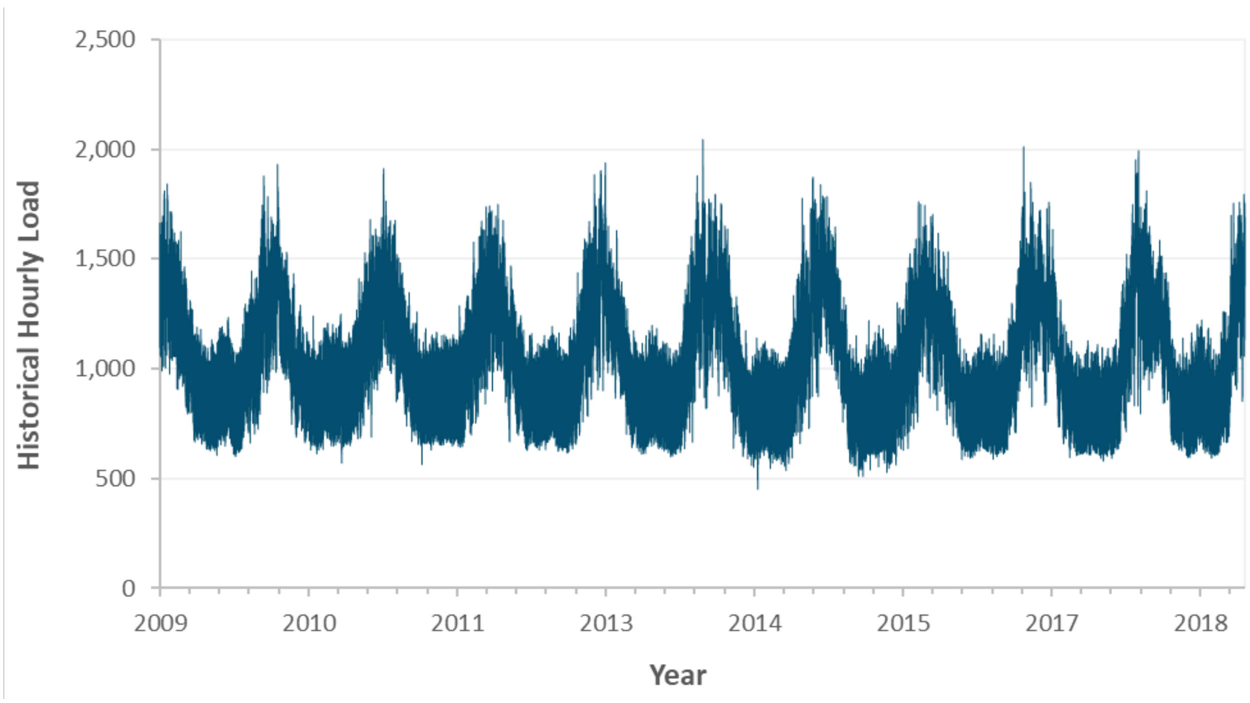
To calculate ELCC for the portfolio of dispatch-limited resources, these resources are first removed from the system which reduces its reliability (increases LOLE) and then "perfect" dispatchable resources with no forced outages are added to the system using a Newton method algorithm until the system returns to its original level of reliability. The quantity of perfectly dispatchable resources required to return the system to the original level of reliability is the ELCC of those dispatch-limited resources.

3 Key Inputs and Assumptions

3.1 Load

To create a synthetic load profile based on an extended weather record, E3 gathered recent historical firm hourly load data from NSPI for the years 2009-2018 which is shown in Figure 18. Non-firm load, namely the Port Hawkesbury paper mill, was excluded from this analysis since NSPI does not include these loads in their capacity planning processes.

Figure 18: Actual Historical Hourly Load for NSPI



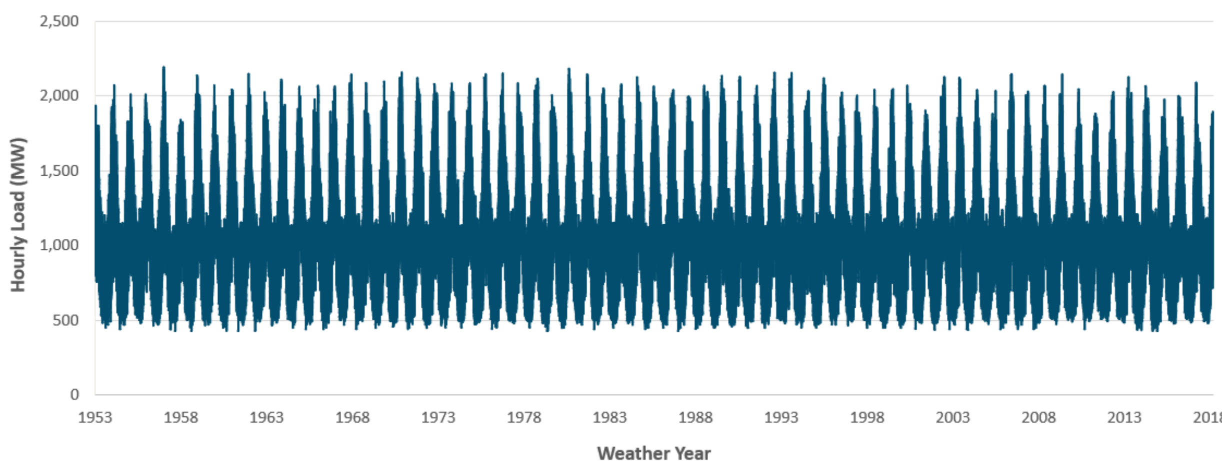
E3 also gathered historical maximum and minimum temperatures published by the Canadian government for 3 geographically diverse weather stations in Nova Scotia for the years 1953-2018.[1]

Table 5: List of Weather Stations for Historical Temperature Data

Location	Station Name	Site ID
Halifax, NS	ST MARGARET'S BAY	6456
Greenwood, NS	GREENWOOD A	6354
Cape Breton, NS	SYDNEY A	52518

Using a neural network regression process described in Section 2.2.1, E3 developed the following hourly load profile that represents load in NSPI service territory under 2020 population and economic conditions across the weather years 1953-2018.

Figure 19: Hourly Load for Forecast 2020 Population and Economic Conditions Under Historical Weather Years 1953-2018



[1] http://climate.weather.gc.ca/historical_data/search_historic_data_e.html

Averaging load by month of year and hour of day yields Figure 20. This figure shows that load is on average highest during the winter months, particularly during the late evening and morning which corresponds with winter heating load spikes. Load is lowest during summer evenings but due to air conditioning can also increase during the middle of the day during summer.

Figure 20: Month/Hour Average Load (GW)

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	1.3	1.2	1.2	1.2	1.2	1.2	1.4	1.5	1.6	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.6	1.7	1.7	1.6	1.6	1.5	1.4	1.3
Feb	1.3	1.2	1.2	1.2	1.2	1.3	1.4	1.5	1.6	1.6	1.6	1.5	1.5	1.5	1.4	1.4	1.5	1.6	1.6	1.6	1.6	1.5	1.4	1.3
Mar	1.1	1.1	1.1	1.1	1.1	1.2	1.3	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.3	1.2	1.1
Apr	0.9	0.8	0.8	0.8	0.9	1.0	1.1	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.1	1.0	1.0	0.9
May	0.7	0.7	0.6	0.7	0.7	0.8	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.7
Jun	0.6	0.6	0.6	0.6	0.6	0.7	0.8	0.9	0.9	1.0	1.0	1.0	1.0	0.9	0.9	1.0	1.0	0.9	0.9	0.9	0.9	0.8	0.7	0.6
Jul	0.6	0.6	0.6	0.6	0.6	0.6	0.8	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.8	0.7
Aug	0.6	0.6	0.6	0.6	0.6	0.7	0.8	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.8	0.7	0.7
Sep	0.6	0.5	0.5	0.5	0.6	0.7	0.8	0.9	0.9	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.7	0.6
Oct	0.7	0.6	0.6	0.6	0.7	0.8	1.0	1.0	1.0	1.0	1.1	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.0	0.9	0.8	0.7
Nov	0.9	0.8	0.8	0.8	0.8	0.9	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.2	1.3	1.3	1.3	1.3	1.2	1.1	1.0	0.9
Dec	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.4	1.4	1.5	1.5	1.4	1.4	1.4	1.4	1.4	1.5	1.6	1.6	1.6	1.5	1.4	1.3	1.2

The reliability needs of the NSPI system today are largely driven by peak load events, although this may change in the future as NSPI becomes more reliant on renewable energy and storage. Table 6 contextualizes the magnitude and frequency of peak load events in NSPI which is a result of peak cold weather events. 1-in-2 peak load events signify that the annual peak load will exceed this value every other year while the 1-in-10 peak load signifies that the annual peak will reach this level one out of every ten years due to normal cold weather variability.

Table 6: Peak Load Events Distribution

Peak Load Event	Simulated Firm Peak Load for 2020 (MW)
1-in-2	2,070
1-in-5	2,135

1-in-10	2,149
1-in-20	2,157
1-in-50	2,176

3.2 Operating Reserves

E3 investigated two operating reserve requirements and calculated the target PRM for both cases. A higher operating reserve requirement of **100 MW** represents approximately 5% of NSPI peak load. Note that this value is less than the typical full operating reserve requirements that are held by NSPI in each hour because it only represents the quantity that must be retained before NSPI would begin to shed firm load in the case of a reliability event. In other words, it is assumed in this case that NSPI would shed firm load in order to maintain 100 MW of operating reserves which is a necessary buffer in order to prevent potentially more catastrophic loss of load events should a generator or transmission line unexpectedly fail.

A lower operating reserve requirement of **33 MW** in all hours is also used which represents NSPI's existing spinning reserve requirement. This lower value decreases the target planning reserve margin required to achieve 0.1 days/yr LOLE. Results are presented in Section 4.

Table 7: Operating Reserve Requirements

Case	Operating Reserve Requirement (MW)
Higher Operating Reserve Requirement	100
Lower Operating Reserve Requirement	33

3.3 Existing Resources

The 2020 NSPI system is comprised primarily of dispatchable thermal generation along with a significant quantity of wind and hydro resources. An overview of the generation portfolio by resource type is shown in Table 8.

Table 8: NSPI Resources in 2020

Resource Type	Nameplate Capacity (MW)
Coal	1,081
Oil	231
Natural Gas/Heavy Fuel Oil	462
Biomass/Biogas	76
Run-of-River Hydro	162
Wreck Cove Hydro	212
Annapolis Tidal	19
Wind	596
Solar	1.7
Maritime Link Base Energy Imports	153
Total Supply	**2,994**

3.3.1 DISPATCHABLE

Dispatchable resources in RECAP include coal/petcoke, heavy fuel oil (HFO), natural gas, oil, biomass, biogas, and a subset of hydro resources that have been deemed to have sufficient pondage such that they are equivalent to firm capacity. These resources are modeled with a derated adjusted forced outage rate (DAFOR) which is a reliability metric specific to the Canadian Electricity Association but is identical to the equivalent forced outage rate (EFOR) that is more commonly used in the U.S. The operating capacity, DAFOR, mean time to recovery (MTTR), and maintenance schedule deratings are shown in Table 9.

Table 9: Thermal Resources Overview

Fuel/Tech Type	Unit Name	Operating Capacity (MW)	DAFOR (%)	MTTR (hours)	Maintenance (% De-rate)
HFO/N Gas	Tufts Cove 1	78	36.0%	72	20% (May – Jun)
	Tufts Cove 2	93	19.1%	72	10% (Mar-Apr)
	Tufts Cove 3	147	2.0%	72	20% (Sep-Oct)
	Tufts Cove 4	49	2.9%	72	10% (Jul)
	Tufts Cove 5	49	5.1%	72	10% (Jul)
	Tufts Cove 6	46	1.6%	72	10% (Jul)
Coal/Petcoke	Pt Aconi	168	1.9%	84	32% (Oct); 57% (Nov)
	Lingan 1	153	1.7%	72	9%-26% (Apr-Oct, excl Jul)
	Lingan 2	0	1.7%	72	9%-26% (Apr-Oct, excl Jul)
	Lingan 3	153	4.2%	72	9%-26% (Apr-Oct, excl Jul)
	Lingan 4	153	5.0%	72	9%-26% (Apr-Oct, excl Jul)
	Trenton 5	150	6.8%	72	25% (Jun- Sep)
	Trenton 6	154	4.4%	72	25% (Jun- Sep)
	Tupper 2	150	1.9%	72	67% (Jun); 45% (Jul)
Oil	Burnside 1	33	10.0%	36	10% (Apr-Sep); 5% (Oct)
	Burnside 2	33	10.0%	36	10% (Apr-Sep); 5% (Oct)
	Burnside 3	33	10.0%	36	10% (Apr-Sep); 5% (Oct)
	Burnside 4	33	10.0%	36	10% (Apr-Sep); 5% (Oct)
	Victoria Junction 1	33	10.0%	36	10% (Apr-May, Sep-Oct)
	Victoria Junction 2	33	10.0%	36	10% (Apr-May, Sep-Oct)
	Tusket	33	10.0%	36	No Maintenance
Hydro	Dispatchable Hydro	162	5%	48	No Maintenance
Biomass	Port Hawkesbury	43	1.2%	72	No Maintenance

	IPP Biomass	31	1.2%	72	No Maintenance
Biogas	IPP Biogas	2	1.2%	72	No Maintenance
Total Operating Capacity (MW)		**2,012**			

3.3.2 HYDRO

NSPI hydro is modeled in RECAP through two distinct methods: dispatchable and dispatch-limited. Dispatchable hydro is modeled identically to thermal resources and the hydro resources that are included in this category are listed in Table 10. All hydro resources except for Wreck Cove are modeled as dispatchable resources because they are deemed to have sufficient pondage such that they are equivalent to firm resources from a reliability perspective. Wreck Cove is modeled as a dispatch-limited resource using a daily “hydro budget” of 500, 800, or 1,100 MWh depending on month of year which the models dispatches into the highest net load hours as described in Section 2.2.3.

Table 10: Hydro Resources Overview

Category	Resource Name	Max Capacity (MW)	
Dispatchable	Tusket	2.4	Assumed to be available to dispatch at maximum capacity during peak load hours,
	St Margarets	10.8	
	Sheet Harbour	10.8	

	Dickie Brook	3.8	because they have enough pondage to ride through an event of any duration
	Nictaux	8.3	
	Lequille	11.2	
	Avon	6.8	
	Black River	22.5	
	Paradise	4.7	
	Mersey	42.5	
	Fall River	0.5	
	Sissiboo	24	
	Bear River	13.4	
Subtotal		**161.7**	
Dispatch-Limited	Wreck Cove	212	Daily budget: 500 MWh/day in June; 800 MWh/day in Apr, Jul-Nov; 1,100 MWh/day in Dec-Mar
Subtotal		**212**	

3.3.3 TIDAL

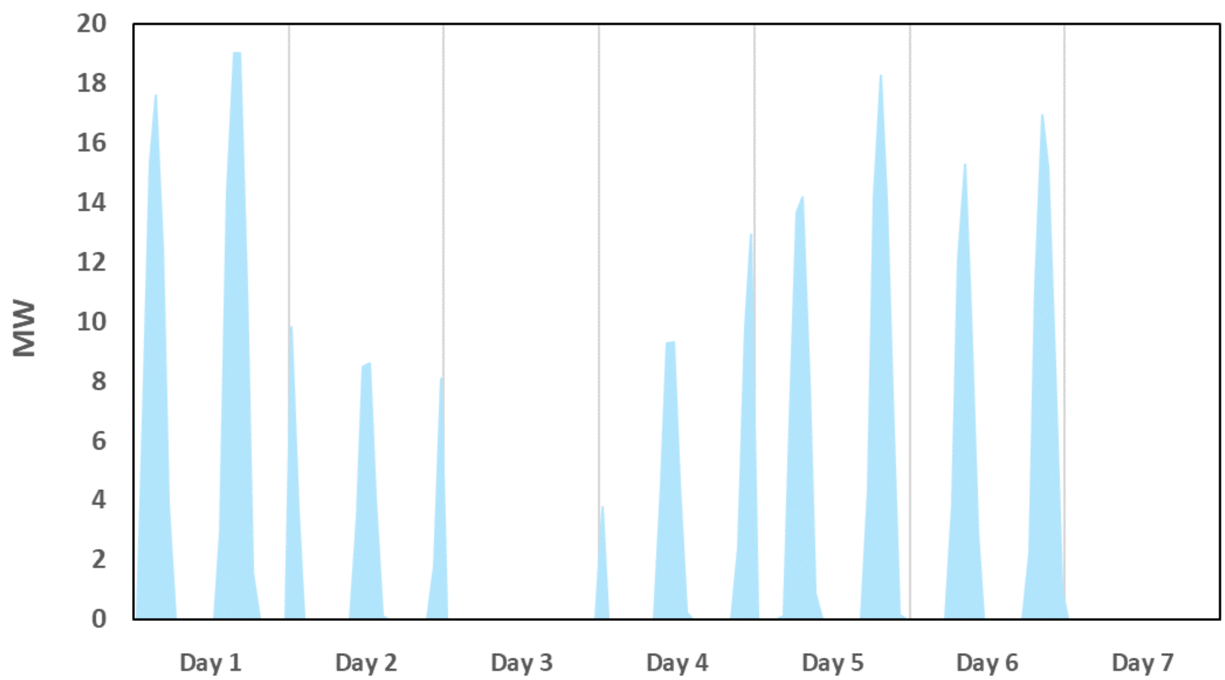
Nova Scotia is home to one of the premier tidal resources in the world due to the enormous tides that occur each day in the Bay of Fundy. Despite this, tidal energy still comprises a relatively small percentage of total NSPI resources which are shown in Table 11.

Table 11: Tidal Resource Overview

Installed Capacity (MW)	Capacity Factor (%)
19	13.2%

Because tidal resources are not dispatchable and produce energy on a variable and intermittent basis, they are modeled in RECAP as variable resources similar to wind and solar. Actual historical tidal profiles from the years 2014-2018 were provided to E3 by NSPI. A sample weekly tidal generation profile is shown in Figure 21.

Figure 21: Illustrative Tidal Weekly Generation



3.3.4 WIND

NSPI currently has nearly 600 MW of installed wind capacity that provides nearly 20% of annual generation. These resources are located across the province as shown in Figure 22.

Figure 22: Map of NSPI Wind Locations

E3 used actual historical wind generation profiles for the years 2011-2018 (8 years total) that were provided by NSPI to model the variable wind resource in RECAP. Wind production data for pre-2011 was excluded from the dataset since the limited installed quantity of wind is not representative of the currently geographic diversity that the existing wind fleet exhibits. Since installed wind capacity was increasing from 2011-2018, E3 calculated the hourly capacity factor in each hour over this time period and then scaled this hourly profile by the installed MW that are forecasted to be on the system in 2020. Table 12 provides the total installed capacity in 2020 and annual capacity factor.

Table 12: Wind Resource Overview

Installed Capacity (MW)	Capacity Factor (%)
596	35.2%

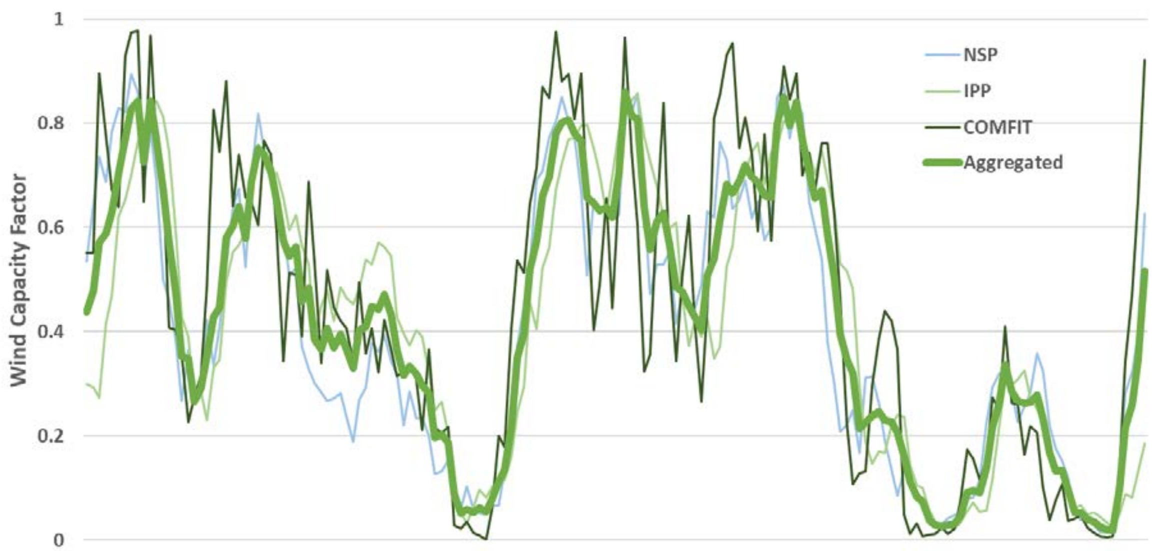
Wind in Nova Scotia exhibits a consistent seasonal and daily pattern which is shown in Figure 23. The wind generation is high in wintertime, especially at night and early morning, and low in summertime. As shown in Figure 20: Month/Hour Average Load (GW), NSPI is a winter peaking load system. The strong positive correlation between wind and load enables wind to create a reasonable capacity value.

Figure 23: Average Wind Generation by Month and Hour (MW)

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	253	249	244	243	244	245	245	244	246	241	235	232	231	233	233	235	233	230	230	235	244	246	250	250
Feb	238	239	240	242	243	241	238	236	231	225	217	210	207	207	208	208	207	207	208	211	218	224	231	235
Mar	245	245	242	239	240	238	238	238	237	233	230	232	234	240	245	249	252	252	249	243	239	240	247	251
Apr	214	216	218	219	222	222	221	222	217	210	206	207	211	216	222	227	230	234	225	218	211	207	212	216
May	201	202	202	204	200	199	196	193	186	178	174	177	182	190	199	205	212	213	208	203	197	194	199	205
Jun	192	193	192	190	185	183	181	174	162	153	147	147	151	161	171	181	188	191	191	185	179	180	185	190
Jul	173	175	174	174	171	167	163	157	143	130	121	119	124	131	139	146	150	152	152	148	145	150	162	170
Aug	163	161	160	158	155	151	147	145	136	124	116	113	118	125	132	138	141	144	141	137	138	146	158	164
Sep	207	209	209	205	200	196	194	195	192	183	172	166	167	173	179	182	182	181	174	171	178	191	198	202
Oct	242	242	243	239	235	234	234	235	234	230	221	216	216	217	219	220	220	219	215	218	226	238	243	247
Nov	250	250	247	247	248	248	249	249	249	245	241	237	234	234	234	234	229	229	233	238	245	253	254	255
Dec	248	247	243	239	241	242	240	238	239	235	231	227	225	225	224	224	222	222	229	241	252	259	262	259

While wind does exhibit strong seasonal and daily patterns, day-to-day production can be quite variable due to specific weather events. Due to Nova Scotia's relatively small size, wind generation tends to be highly correlated across the peninsula which is illustrated in Figure 24 for a sample week. When it is windy, it tends to be windy everywhere, and vice versa.

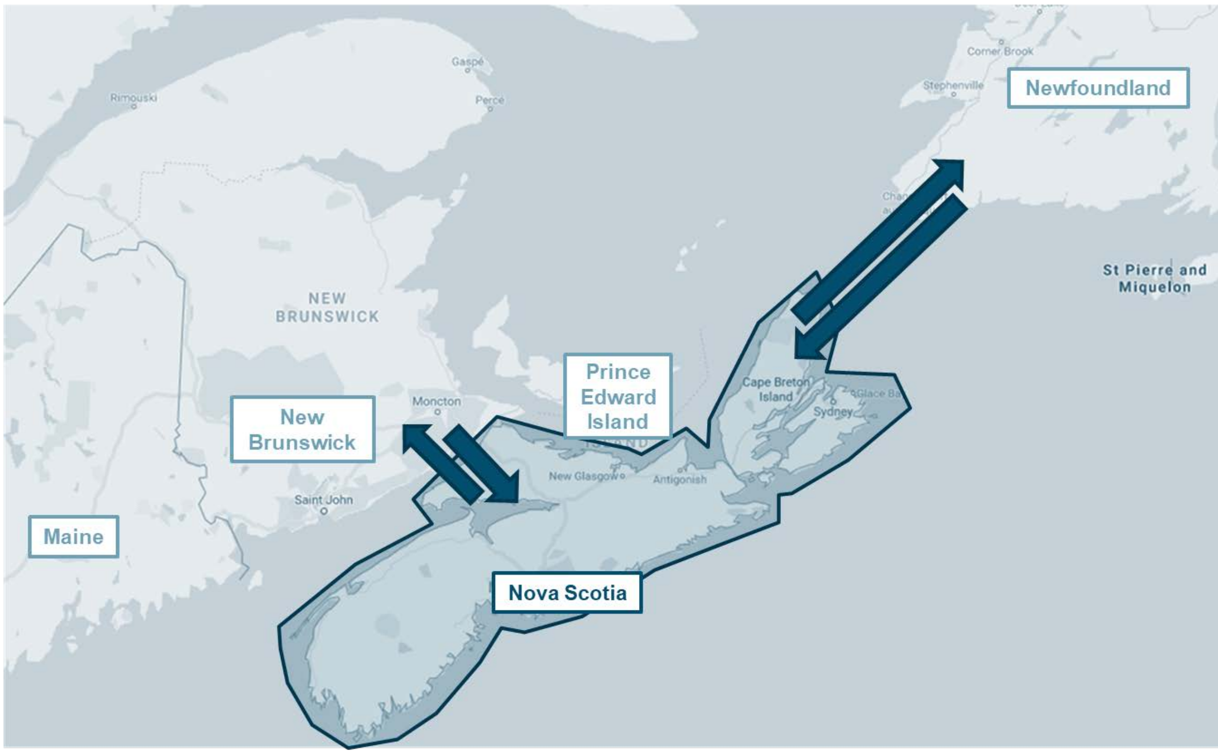
Figure 24: Example of Correlation Between Wind Sites in Nova Scotia (7 days in January)



3.3.5 IMPORTS

The NSPI system is electrically connected to the broader Eastern Interconnection through two points: an overland transmission line to New Brunswick and the “Maritime Link”, an undersea transmission line to Newfoundland.

Figure 25: Transmission Map



However, despite this transmission capability, NSPI only relies on 153 MW of firm capacity over the Maritime Link due to the contracting that would be required to increase this. While energy may be imported through these interconnections, only imports with specifically contracted firm capacity can have a non-zero ELCC. This Muskrat Falls hydro resource is available during on-peak hours (7am-11pm) beginning in 2020. The Maritime Link is comprised of two transmission lines (Pole 1 and Pole 2) with each line having a 96% availability factor, which combine to yield a 0.2% DAFOR. Delivery of the Maritime Link block is also reliant on the Labrador Island Link (LIL), an HVDC bi-pole arrangement. Finally, the Muskrat Falls hydro facility has an assumed long-term DAFOR of 1.93%. For planning purposes, the cumulative availability factors combined are assumed to yield a 2% DAFOR which is implemented in the RECAP model.

3.4 Future Resources

In addition to existing resources, this study examines the potential reliability contribution (i.e. ELCC) of potential new wind, solar, storage, and DR resources that may play a role in the upcoming NSPI IRP. This section describes the characteristics of these potential future resources.

3.4.1 WIND

This study examines the ELCC of existing wind (596 MW) and future wind resources up to 1,000 MW. Because existing wind is geographically diverse throughout the province, it is assumed that new wind would have on average the same aggregate profile as existing wind and so the existing profile is scaled upward to examine the reliability contribution of incremental wind. Future wind maintains a 35% capacity factor.

3.4.2 SOLAR

Because there is limited existing solar capacity in Nova Scotia, E3 simulated hourly solar generation profiles using hourly insolation data produced by National Solar Radiation Database (NSRDB) for the years from 2008 to 2010. Hourly profile were simulated using the System Advisor Model (SAM) produced by the U.S. National Renewable Energy Laboratory (NREL). This model takes in hourly insolation data, PV panel type, tilt, inverter loading ratio, along with key system characteristics and produces hourly energy generation.

Table 13: Key Solar Assumptions

Solar Assumption	Value
Type	Single-Axis Tracking
Tilt	30
Inverter Loading Ratio	1.3

Sites	50 geographically diverse locations across NS

Average solar generation by month and hour from the resultant solar generation simulations is shown in Figure 26 and yields and annual average capacity factor of 15.0%.

Figure 26: Average Simulated Solar Generation by Month and Hour (MW)

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan										0.1	0.3	0.3	0.4	0.4	0.3	0.3	0.2							
Feb									0.1	0.2	0.4	0.5	0.5	0.5	0.5	0.4	0.4	0.3						
Mar								0.0	0.2	0.4	0.6	0.7	0.8	0.8	0.7	0.7	0.6	0.4	0.2					
Apr							0.0	0.2	0.4	0.6	0.8	0.9	0.9	0.9	0.9	0.8	0.7	0.5	0.3					
May							0.1	0.3	0.5	0.7	0.9	1.0	1.0	1.0	0.9	0.9	0.8	0.6	0.4	0.2				
Jun							0.2	0.3	0.5	0.7	0.9	1.0	1.0	1.0	1.0	0.9	0.8	0.7	0.5	0.3				
Jul							0.1	0.3	0.5	0.7	0.9	1.0	1.0	1.0	1.0	0.9	0.8	0.7	0.5	0.3				
Aug							0.0	0.2	0.4	0.7	0.8	1.0	1.0	1.0	1.0	0.9	0.8	0.6	0.4	0.2				
Sep								0.1	0.3	0.6	0.7	0.8	0.8	0.8	0.8	0.7	0.6	0.4	0.2					
Oct									0.2	0.4	0.5	0.6	0.6	0.6	0.6	0.5	0.4	0.2						
Nov									0.1	0.2	0.4	0.5	0.5	0.5	0.4	0.4	0.3							
Dec										0.1	0.2	0.3	0.3	0.3	0.3	0.2	0.2							

3.4.3 STORAGE

E3 modeled four different durations of storage in this study: 1-hour, 2-hour, 4-hour, and 12-hour. While the most commonly installed Li-Ion storage resources today are 4-hour systems, shorter duration storage resources are commercially available. 12-hr duration Li-Ion storage is not common today but nonetheless the results are instructive for what reliability value a system with this duration might provide. These systems were modeled with an 84% roundtrip efficiency factor.

3.4.4 DEMAND RESPONSE

Demand response (DR) represents a resource where the system operator can call on certain customers during times of system stress to reduce their load and prevent system-wide loss-of-load events. However, DR programs have limitations on how often they can be called and how long participants respond when they are called. E3 modeled three different illustrative demand response programs in this study to help inform how existing and potential new demand response programs might help to meet the reliability needs of NSPI. In this framework, a "call" represents a load that is either manually or automatically dispatched by the system operator and consequently reduces system load by a defined MW value. Each modeled demand response program is characterized by 1) the number of times that a participant can be called upon per year to reduce load and 2) the duration that a participant reduces load for per call. This study assumes perfect foresight of the system operator such that a DR call is never "wasted" when it wasn't actually needed for system reliability. Table 14 lists the characteristics of the three modeled demand response programs in this study.

Table 14: Characteristics of Modeled Demand Response Programs

DR Program	Number of Annual Calls	Duration of Each Call (hours)
Illustrative Program 1	5	2
Illustrative Program 2	10	4
Illustrative Program 3	20	12

4 Results

4.1 2020 Reliability Statistics

Using the forecasted 2020 loads and resources, Table 15 presents the expected reliability statistics for the NSPI system for both the higher and lower operating reserve requirement cases.

Table 15: 2020 Reliability Statistics

Metric	Units	Higher Operating Reserve Requirement Case	Lower Operating Reserve Requirement Case
Loss of Load Expectation (LOLE)	days/yr	0.19	0.04
Annual LOLP (%)	%	15.4%	3.0%
Loss of Load Hours (LOLH)	hrs/yr	1.29	0.016
Loss of Load Events (LOLEV)	events/yr	0.17	0.03
Expected Unserved Energy (EUE)	MWh/yr	49	7.6
Normalized EUE	% of annual load	0.0005%	0.00008%
1-in-2 Peak Load	MW	2,070	2,070
PRM Requirement	% of peak	21.0%	17.8%

The target planning reserve margin (PRM) is explicitly called out in Table 16. This value represents the quantity of installed capacity that NSPI needs to hold above the 1-in-2 median annual peak load in order to meet a target reliability of 0.1 days/year LOLE.

Table 16: Target Planning Reserve Margin

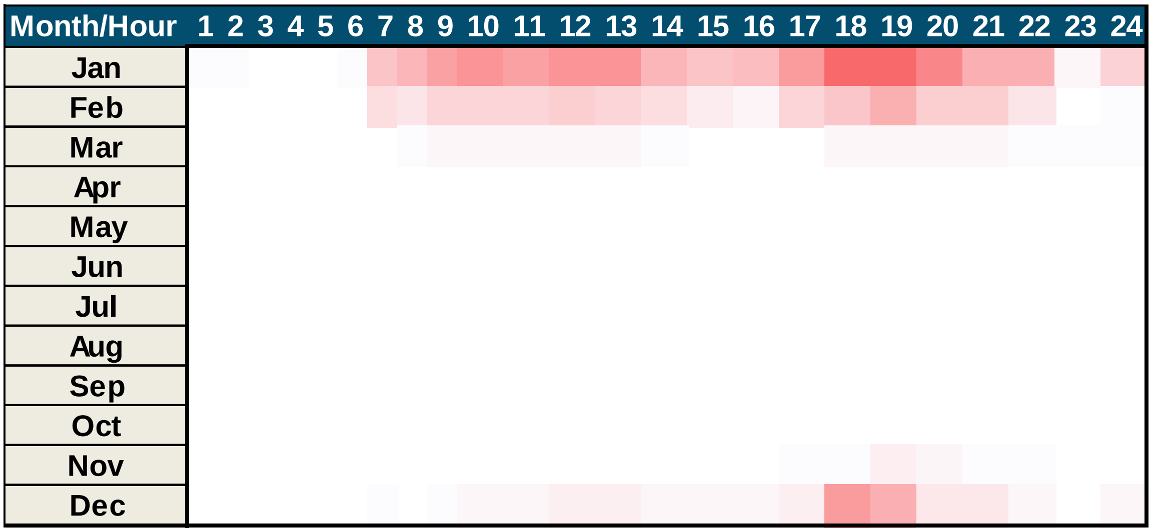
Target PRM
17.8% - 21.0%

A reduction of 67 MW (100 MW to 33 MW) in the operating reserve requirement between the higher and lower case represents about 3.2% of NPSI peak load, so it is unsurprising that the PRM requirement decreases by approximately 3.2%. E3 expects that this relationship with the target PRM would hold for larger or smaller operating reserve requirements.

Notably, in the higher operating reserve requirement case the calculated LOLE 2020 reliability statistic of 0.19 days/year exceeds to target reliability standard of 0.1 days/year. Because of this, it follows that NSPI is not forecasted to meet a 21.0% PRM in 2020 and only achieves a 19.1% PRM, 38 MW below the target.

The LOLE is primarily driven by peak load events that result from cold weather and occur primarily in the winter months of December, January, and February in the morning and evening when electric heating loads are highest. Figure 27 shows the loss of load probability by month and hour for the 2020 NSPI system.

Figure 27: Average LOLP by Month and Hour for the 2020 NSPI System



4.2 Load and Resource Balance

Table 17 shows the contribution of each resource type toward the target PRM in the higher operating reserve requirement case. As described in Section 1.3, dispatchable resources (coal, oil, natural gas, biogas, biomass, and some hydro resources) are counted by convention using their net dependable capacity while dispatch-limited resources (wind, solar, tidal) are counted using effective load carrying capability (ELCC).

Table 17. 2020 Load and Resources

Load	
Firm Peak Load Net of DSM (MW)	2,070
Target Reliability Standard	0.1 days/year
Target PRM	21.0%

Total Requirement (MW)	2,504		
Resource	**Nameplate Capacity (MW)**	**Effective Capacity (MW)**	**Effective Capacity (%)**
Coal	1,081	1,081	100%
Oil	231	231	100%
Natural Gas/Heavy Fuel Oil	462	462	100%
Biomass/Biogas	76	76	100%
Run-of-River Hydro	162	154	95%
Wreck Cove Hydro	212	202	95%
Annapolis Tidal	19	2.3	12%
Wind	596	111	19%
Solar	1.7	0.08	5%
Maritime Link Base Energy Imports	153	151	98%
Total Supply (MW)	**2,994**	**2,470**	78%
Surplus/Deficit (MW)	**-38**		

Despite the industry standard convention to count the contribution toward PRM of dispatchable resources at their nameplate capacity, these resources do experience forced outages that mean they are less reliable than "perfect" capacity that is always available with no forced outages. Because ELCC is measured in equivalent perfect capacity, it is possible to calculate an ELCC for thermal resources to compare on an equal basis with the ELCC of dispatch-limited resources. Table 18 shows the calculated ELCC for all resource types taking into account the forced outages of thermal units and other interactive effects such as the lumpiness of units and the resulting impact on system reliability.

Table 18: ELCC of All Resources

Resource	Nameplate Capacity	Net Capacity	ELCC %

Coal	1081	958	92%
Oil	231	191	78%
HFO/NG	462	376	75%
Biomass/Biogas	76	69	97%
Run-of-River Hydro	162	154	95%
Wreck Cove Hydro	212	201	95%
Annapolis Tidal	19	2.3	12%
Wind	596	113	19%
Solar	2	0.09	5%
Maritime Link Base Energy Imports	153	150	98%
Total	**2,994**	**2,215**	

4.3 Effective Load Carrying Capability

This section presents the effective load carrying capability (ELCC) of the dispatch-limited resources wind, solar, storage, and demand response for both existing quantities of capacity and potential future capacity of these resources. More info on ELCC can be found in Section 1.4.

4.3.1 WIND

The average ELCC of the 596 MW of wind currently installed on the NSPI system is 19% or 111 MW. The ELCC value of adding new wind to the NSPI system is measured by the marginal ELCC and is 11%, meaning that each additional MW of wind contributes 0.11 MW of firm capacity to PRM requirements.

Figure 28 and Figure 29 show the average and marginal ELCC, respectively, at different installed quantities. Both figures highlight very clearly the diminishing ELCC returns of additional wind capacity which is consistent with E3 findings for other jurisdictions across North America. This phenomenon is a result of the fact that while wind may be able to provide some ELCC due to generation during the peak load hours, the addition of significant quantities of wind shifts the net peak load hours to periods of low wind generation which by definition is difficult for wind to contribute energy to, reducing the marginal ELCC.

Figure 28: Average Wind ELCC

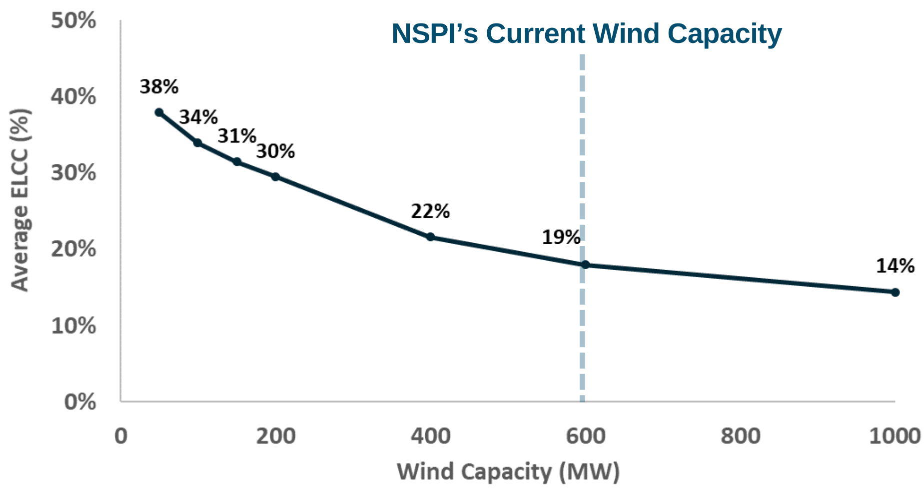
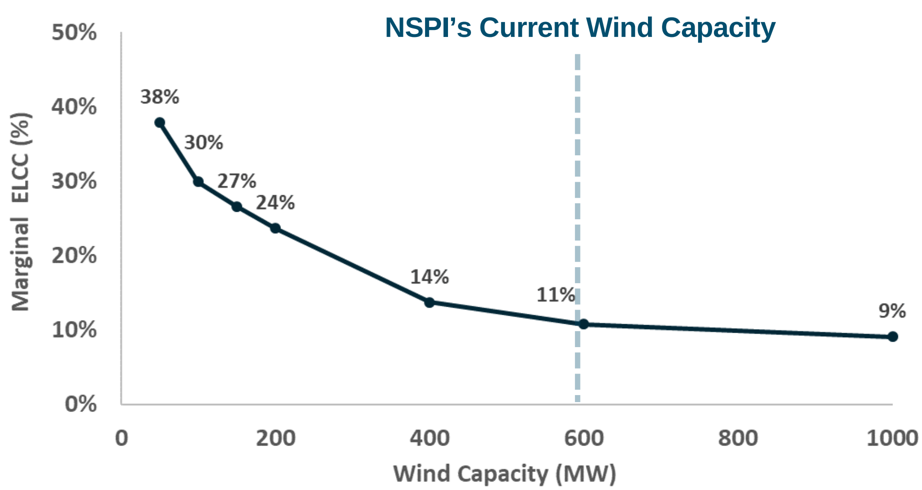


Figure 29: Marginal Wind ELCC



4.3.2 SOLAR

The NSPI system currently has a very small amount of solar capacity at only 1.7 MW which has an average and marginal ELCC of 5%. Solar has very limited ELCC in Nova Scotia due to poor correlation with the net peak load hours, which primarily occur on winter evenings. Beyond initial penetrations of solar capacity, the marginal capacity value declines to 0%. These values are highlighted in Figure 30 and Figure 31.

Figure 30: Average Solar ELCC

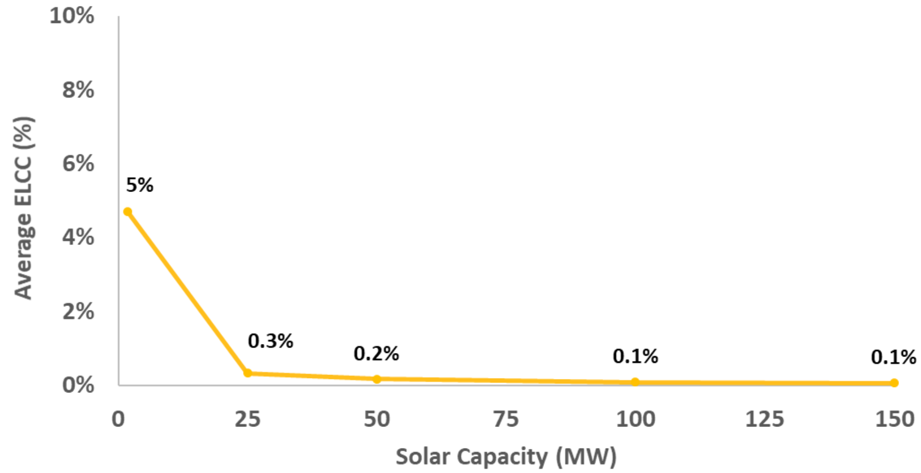
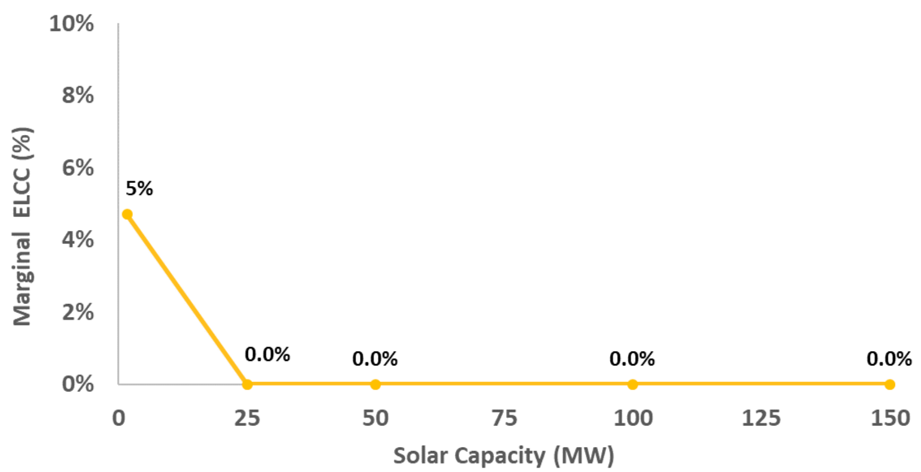


Figure 31: Marginal Solar ELCC



4.3.3 STORAGE

The NSPI system currently has no energy storage in its portfolio, but this study examines the potential contribution of this resource toward resource adequacy needs as there is the potential that it may play a meaningful role in Nova Scotia going forward.

Like renewables and other dispatch-limited resources, storage exhibits diminishing ELCC returns to additional capacity as illustrated in Figure 32 and Figure 33. For storage with a 4-hour duration, the average ELCC declines from 90% at initial penetrations to 55% at 200 MW and the decline in marginal ELCC is even more stark with a value of 35% at 200 MW. The decline in storage ELCC is due to the fact that, after storage has clipped the peak demand periods, the next tranche of peak period becomes longer. Not only do the net peak load periods increase in duration as storage capacity increases, but the ability of storage to charge during off peak resources also becomes more constrained since firm capacity that can charge the storage is being removed from the system and substituted with storage capacity which cannot generate energy. Increasing the duration of storage increases the ELCC and slows the rate of diminishing return on ELCC as additional storage capacity is added.

Figure 32: Average Storage ELCC

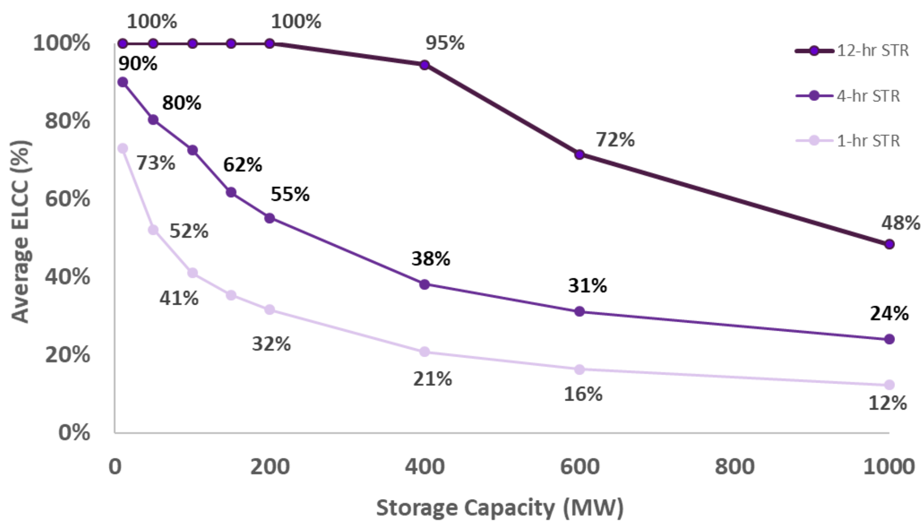
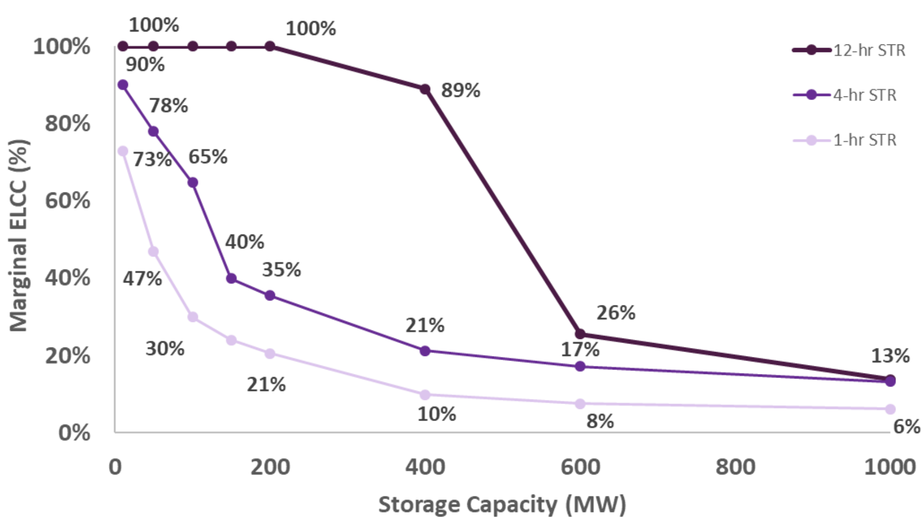


Figure 33: Marginal Storage ELCC



In addition to these results, E3 examined the ELCC of storage with the availability of additional off-peak import capability and found that the results were not significantly different.

4.3.4 DEMAND RESPONSE

This study examines three illustrative demand response (DR) programs with different numbers of calls and durations per call that are described in Section 3.4.4. These results are not meant to map directly to specific existing DR programs but rather inform system planners of the ELCC value that a DR program with similar attributes might provide. Like with all of the previous results, DR exhibits diminishing average and marginal ELCC value which is illustrated in Figure 34 and Figure 35.

Figure 34: Average DR ELCC

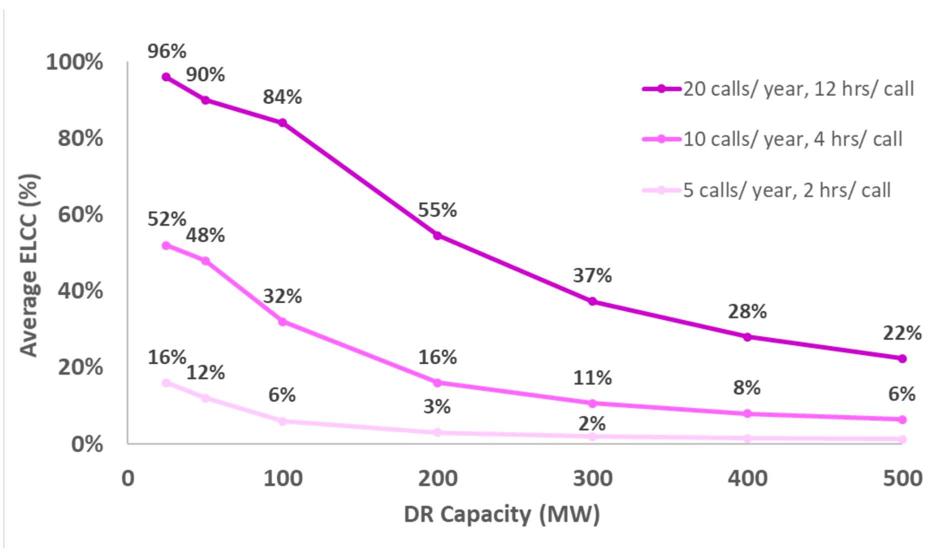
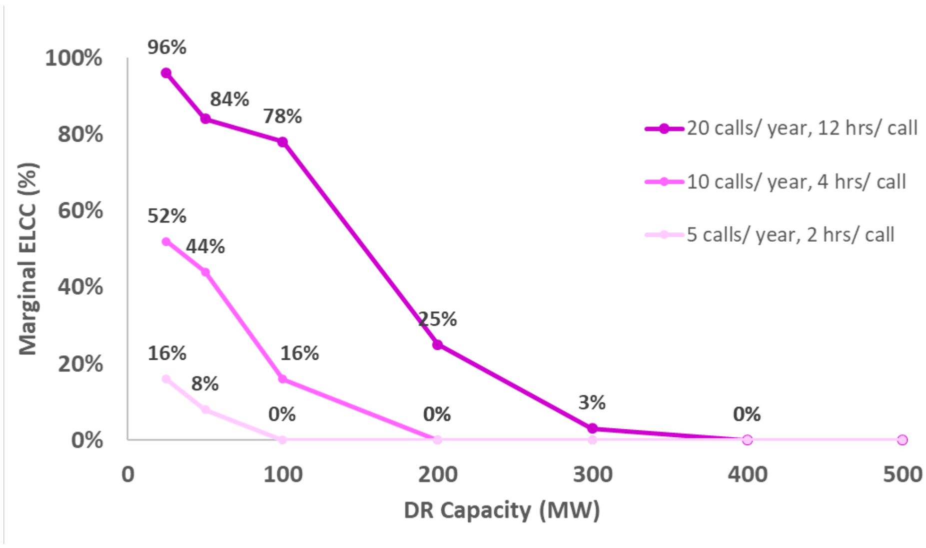


Figure 35: Marginal DR ELCC

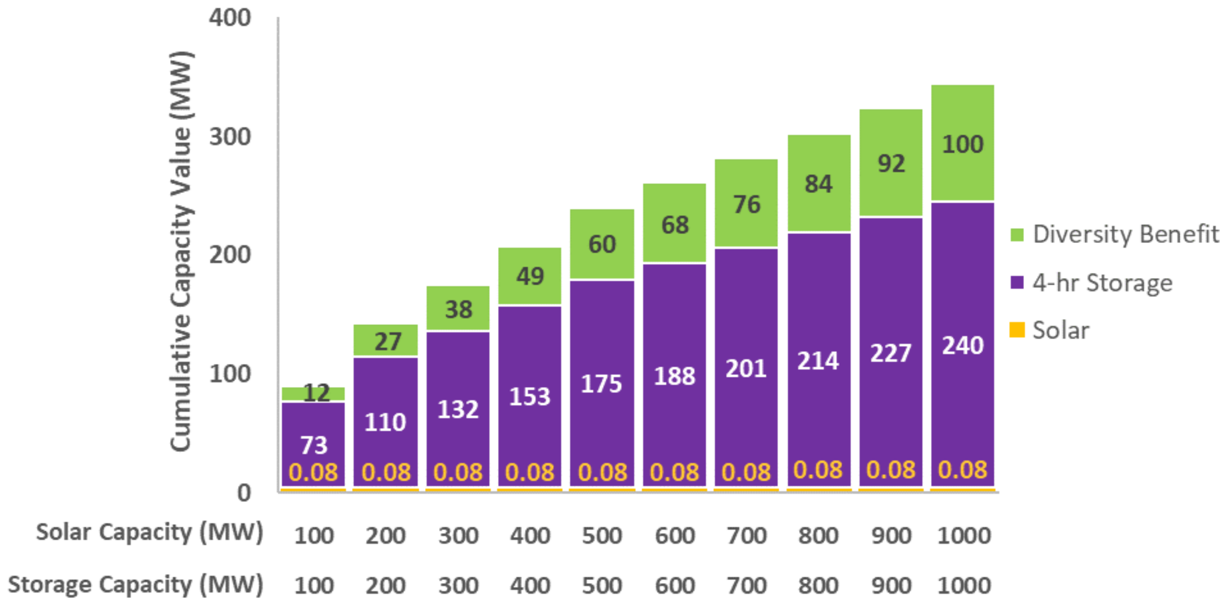


4.3.5 DIVERSITY

As described in Section 1.4, a portfolio of dispatch-limited resource often provides a combined ELCC more than the sum of their individual parts. In particular, renewables + storage provide a unique set of synergies since renewables can provide the energy that storage needs to provide ELCC and storage provides the dispatchability that renewables need to provide ELCC. This study analyzes the diversity benefit of two sets of dispatch-limited resources: solar + storage and wind + storage.

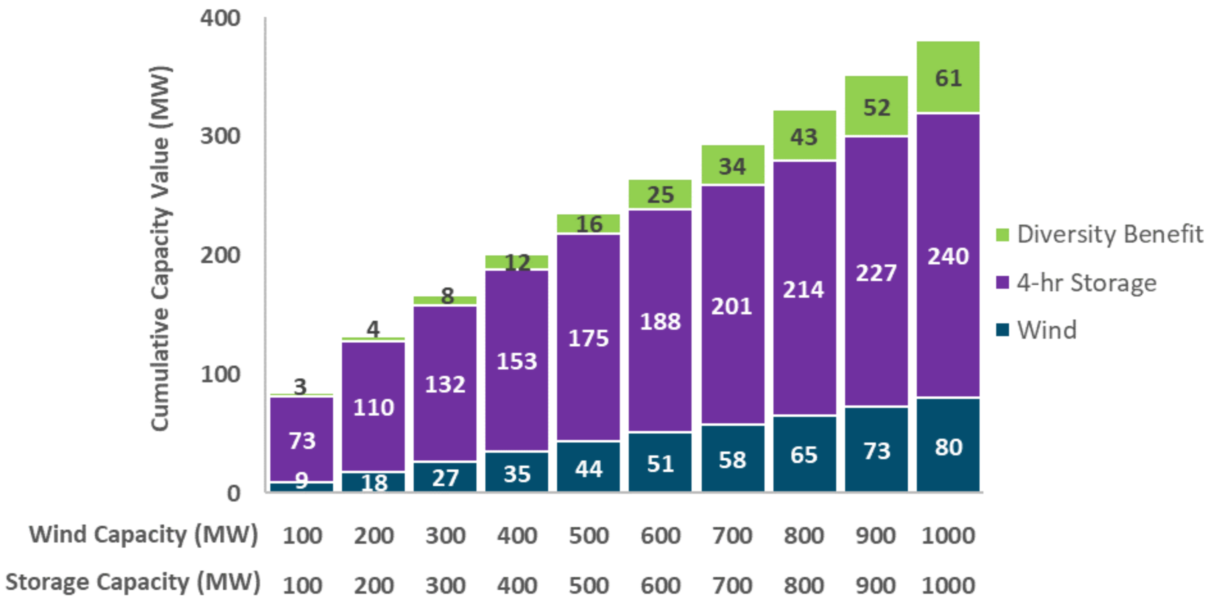
When solar and storage are paired together, they create diversity value due to interactive effects. Solar and storage have a particularly strong diversity benefits since solar is not naturally coincident with the NSPI winter evening peak and storage is able to shift some of that solar production from the middle of the day into the peak hours when it can provide ELCC.

Figure 36: ELCC Diversity Benefit of Solar + Storage



When wind and storage are paired together, they can also create diversity value. Because wind is more naturally coincident with the NSPI winter evening peak than solar, the incremental benefit from storage is less than in the case of solar, but nonetheless there is still a diversity benefit.

Figure 37: ELCC Diversity Benefit of Wind + Storage



5 Conclusions

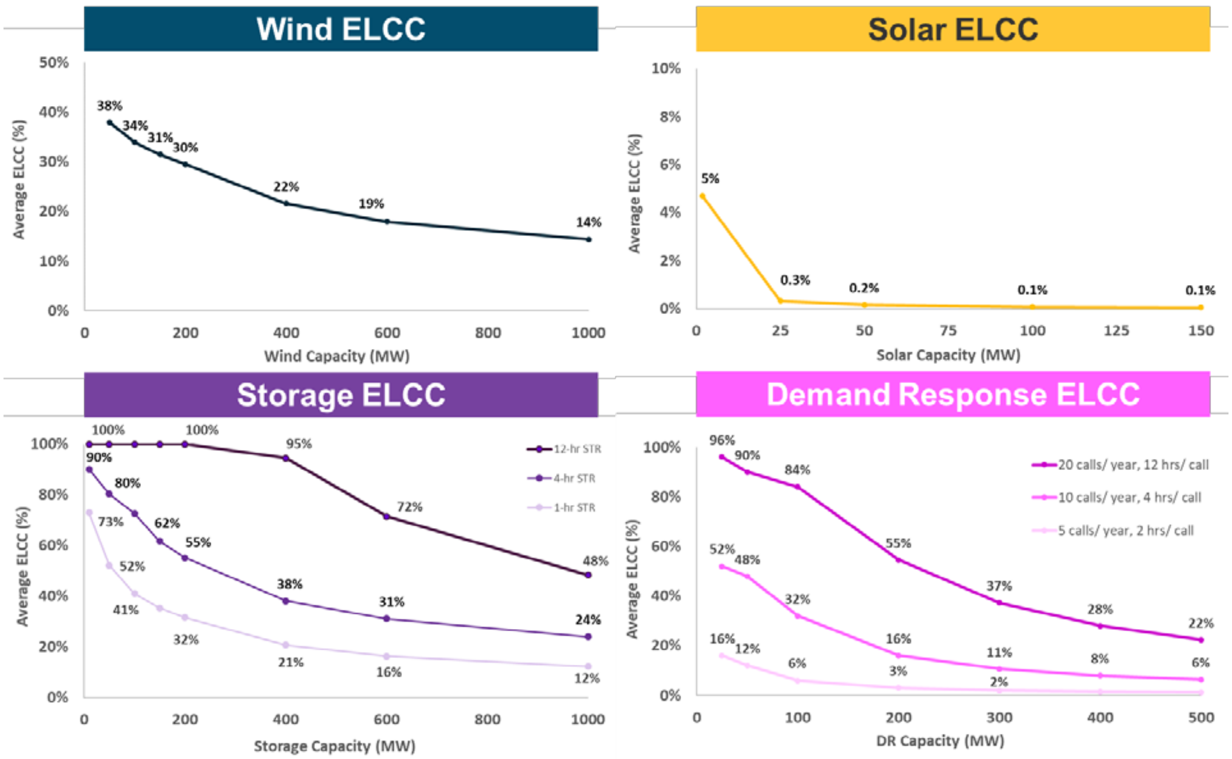
This study provides an update to several important assumptions to be used by Nova Scotia Power Inc. (NSPI) in the integrated resource planning (IRP) process to ensure that NSPI maintains an appropriate level of resource adequacy, so that it can continue to provide reliable and affordable power to its customers.

This study finds that in order to meet a 0.1 days/year loss of load expectation (LOLE) target, NSPI should maintain between a 17.8% and 21.0% planning reserve margin (PRM).

Target PRM
17.8% - 21.0%

The calculated LOLE for the forecasted 2020 NSPI system on the high end is 0.19 days/year which exceeds the target reliability standard of 0.1 days/year. This is consistent with the finding that NSPI is not forecasted to meet a 21.0% PRM in 2020 and only achieves a 19.1% PRM.

This study finds that the dispatch-limited resources wind, solar, storage, and demand response can contribute effective load carrying capability (ELCC) toward meeting the planning reserve margin requirement, but have diminishing returns as additional capacity is added to the system.


Wind ELCC
Average ELCC (%)
Wind Capacity (MW)
38%
34%
31%
30%
22%
19%
14%
Solar ELCC
Average ELCC (%)
Solar Capacity (MW)
5%
0.3%
0.2%
0.1%
0.1%
Storage ELCC
Average ELCC (%)
Storage Capacity (MW)
12-hr STR
4-hr STR
1-hr STR
100%
100%
95%
72%
48%
90%
80%
62%
55%
38%
31%
24%
73%
52%
41%
32%
21%
16%
12%
Demand Response ELCC
Average ELCC (%)
DR Capacity (MW)
20 calls/ year, 12 hrs/ call
10 calls/ year, 4 hrs/ call
5 calls/ year, 2 hrs/ call
96%
90%
84%
55%
37%
28%
22%
52%
48%
32%
16%
11%
8%
6%
16%
12%
6%
3%
2%

6 Appendix

Table 19. Wind ELCC

Wind Capacity (MW)	ELCC (MW)	Average ELCC	Marginal ELCC
50	19	38%	38%
100	34	34%	30%
150	47	31%	27%
200	59	30%	24%
400	86	22%	14%
600	108	18%	11%
1,000	144	14%	9%
1,500	182	12%	8%
2,000	212	11%	6%
5,000	288	6%	3%

Table 20. Solar ELCC

Solar Capacity (MW)	ELCC (MW)	Average ELCC	Marginal ELCC
1.7	0.08	4.7%	4.7%
25	0.08	0.3%	0.0%
50	0.08	0.2%	0.0%
100	0.08	0.1%	0.0%
150	0.08	0.1%	0.0%
200	0.08	0.0%	0.0%
400	0.08	0.0%	0.0%

Table 21 1-hr Storage ELCC

1-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	7	73%	73%
50	26	52%	47%
100	41	41%	30%

150	53	35%	24%
200	63	32%	21%
400	83	21%	10%
600	98	16%	8%
1,000	122	12%	6%

Table 22. 2-hr Storage ELCC

2-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	9	90%	90%
50	33	65%	59%
100	57	57%	48%
150	71	47%	28%
200	82	41%	22%
400	108	27%	13%
600	130	22%	11%
1,000	170	17%	10%

Table 23. 4-hr Storage ELCC

4-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	9	90%	90%
50	40	80%	78%
100	73	73%	65%
150	93	62%	40%
200	110	55%	35%
400	153	38%	21%
600	187	31%	17%
1,000	240	24%	13%

Table 24. 12-hr Storage ELCC

12-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	10	100%	100%
50	50	100%	100%
100	100	100%	100%
150	150	100%	100%
200	200	100%	100%
400	378	95%	89%
600	429	72%	26%
1,000	484	48%	14%

Table 25. DR ELCC (5 calls/year, 2 hrs/call)

DR Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
25	4	16%	16%
50	6	12%	8%
100	6	6%	0%
200	6	3%	0%
300	6	2%	0%
400	6	2%	0%
500	6	1%	0%

Table 26. DR ELCC (10 calls/year, 4 hrs/call)

DR Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
25	13	52%	52%
50	24	48%	44%
100	32	32%	16%

200	32	16%	0%
300	32	11%	0%
400	32	8%	0%
500	32	6%	0%

Table 27. DR ELCC (20 calls/year, 12 hrs/call)

DR Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
25	24	96%	96%
50	45	90%	84%
100	84	84%	78%
200	109	55%	25%
300	112	37%	3%
400	112	28%	0%
500	112	22%	0%

Table 28. Solar + 4-hr Storage ELCC

Solar Capacity (MW)	Storage Capacity (MW)	Solar Standalone ELCC (MW)	4-hr Storage Standalone ELCC (MW)	Solar + Storage ELCC (MW)	Diversity Benefit (MW)
100	100	0.1	73	85	12
200	200	0.1	110	138	27
300	300	0.1	132	170	38
400	400	0.1	153	203	49
500	500	0.1	175	235	60
600	600	0.1	188	256	68
700	700	0.1	201	277	76
800	800	0.1	214	298	84
900	900	0.1	227	319	92
1,000	1,000	0.1	240	340	100

Table 29. Wind + 4-hr Storage ELCC

Wind Capacity (MW)	Storage Capacity (MW)	Wind Standalone ELCC (MW)	4-hr Storage Standalone ELCC (MW)	Wind + Storage ELCC (MW)	Diversity Benefit (MW)
100	100	9	73	85	3
200	200	18	110	132	4
300	300	27	132	166	8
400	400	35	153	201	12
500	500	44	175	235	16
600	600	51	188	264	25
700	700	58	201	293	34
800	800	65	214	323	43
900	900	73	227	352	52
1,000	1,000	80	240	381	61

Energy+Environmental Economics

NSPI Resource Options Study

Nova Scotia Power

July 2019

Aaron Burdick, Sr. Consultant
Charles Li, Consultant
Sandy Hull, Sr. Consultant
Zach Ming, Sr. Managing Consultant

Outline

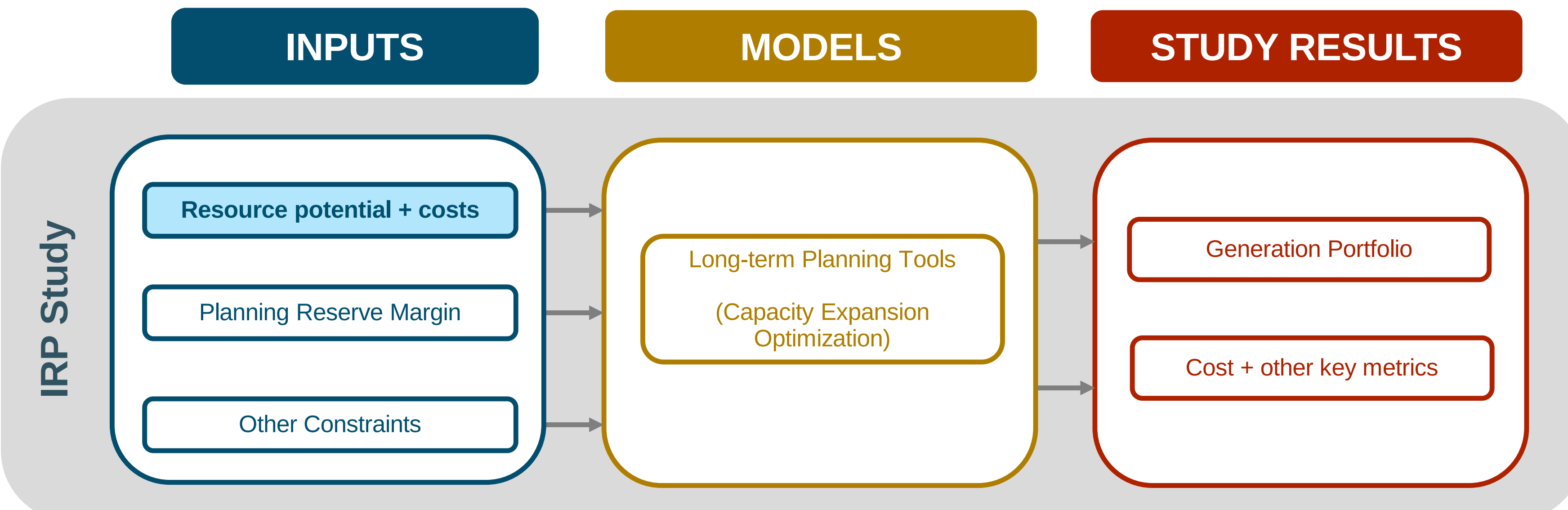
- **Resource options study approach**
- **Summary of proposed assumptions**
- **Details of resource options considered**
  - Renewables
    - Wind, utility-scale PV, biomass, municipal solid waste, tidal
  - Storage
    - Battery storage, compressed air, pumped storage
  - Fossil
    - Natural gas, coal repowering
  - Nuclear
    - Small modular nuclear

Energy+Environmental Economics

Resource options study approach

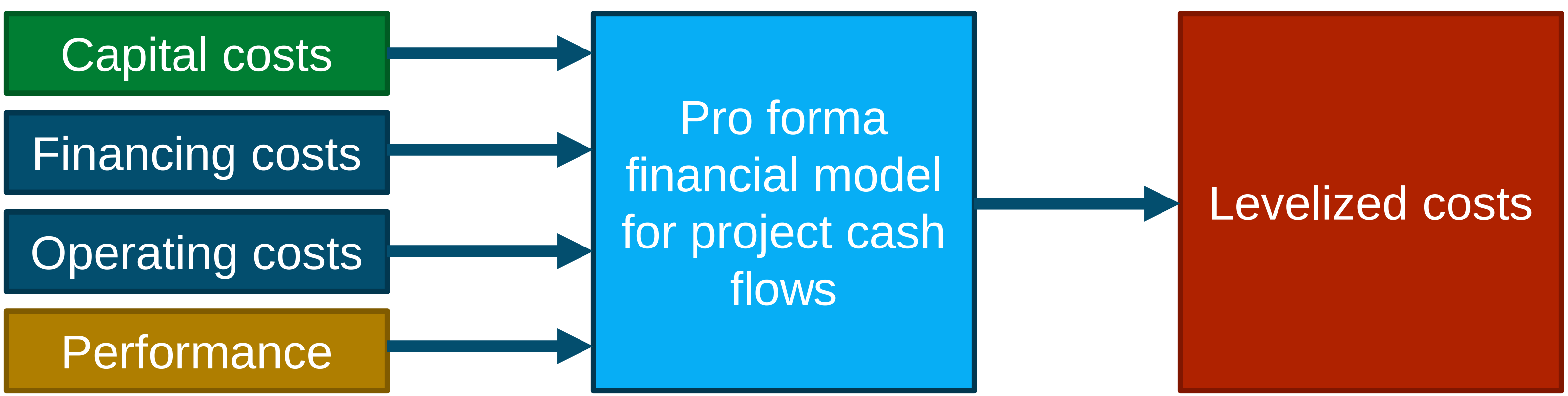
Approach

- **In preparation for its upcoming integrated resource plan, NSPI has asked E3 to provide guidance on resource costs and potential**
  - **Cost:** what are the costs (capital, O&M, fuel) associated with developing and operating each new resource? What future changes are expected?
  - **Performance:** what are the operational constraints associated with each resource (e.g. hourly profiles for wind/solar)
  - **Potential:** how much of the resource can be developed within Nova Scotia (or remotely)?



E3's Pro Forma Model

- **Resource costs are typically quoted in either upfront capital costs ($/kW) or levelized costs ($/MWh) that are indicative of likely PPA prices**
- **Levelized cost of energy* (LCOE) include several other cost factors and assumptions beyond the project's upfront capital cost**
  - Financing costs: cost of capital, financing lifetime, tax rates, and incentives
  - Operating costs: fixed and variable O&M of plant operations ("opex"), including fuel
  - Performance assumptions: amount of energy generation over which fixed costs are spread, i.e. average capacity factor, is a major driver of LCOE
- **E3's Pro Forma model produces both LCOE ($/MWh) at an estimated capacity factor as well as the fixed ($/kW-yr) and variable ($/MWh) cost components**
- **E3 analyzed all resources using NSPI's financing assumptions**
  - Independent power producer financing may result in changes to levelized costs



* In this study, LCOE is calculated using a real discount rate assuming that LCOE escalates at an inflation rate of 2%.

Resource Cost Modeling
Fixed vs. Variable Costs for New Resources

+ **Fixed costs: expenditures required to install and maintain generating capacity, independent of operations**
  - Capital costs:
    - Overnight capital cost (equipment cost, balance of systems, development costs, etc.)
    - Construction financing
    - Nominal interconnection costs (i.e. a short spur line, not longer lines required for remote renewables)
  - Fixed O&M:
    - Operations and maintenance costs incurred independent of energy production
    - Insurance, taxes, land lease payments and other fixed costs
    - Annualized large component replacement costs over the technical life (aka sustaining capital)
+ **Variable costs: marginal costs for each MWh of generation, based on modeled operations**
  - Variable O&M:
    - Operating and maintenance costs (parts, labor, etc.) incurred on a per-unit-energy basis
  - Fuel cost:
    - Commodity costs for fuel ($/MMBtu * heat rate MMBtu/MWh = $/MWh)
+ **Capacity factor: annual energy production per kW of plant capacity**
  - Used to estimate variable costs as well as the spread of fixed costs over expected generation

Resource Options Considered

+ **Fossil fuels:** coal-to-gas, coal-to-biomass, natural gas (CC, CT, reciprocating engine, CC w/ carbon capture and storage)
+ **Renewables:** biomass, municipal solid waste, solar PV, tidal, wind (onshore and offshore)
+ **Energy storage:** li-ion batteries, compressed air, pumped hydro
+ **Emerging technologies**: modular nuclear

Resource Cost Modeling

Step 1: Capital Cost Assumptions

Generic Capital Costs
US/Global

- Third Party Reports
- IRPs
- Industry Surveys
- Actual Project Costs
- E3 Research

+

Local Cost Adjustments
Nova Scotia

- NSPI Cost Estimates
- Terrain+Labor Cost Factors
- Regional Data Sources

+

Future Cost Forecasts
2020-2050

- NREL ATB Cost Forecasts
- Third Party Reports
- E3 Research

=

E3 Recommendations
Nova Scotia, 2019-2050

Resource Capital Costs ($/kW)

NOTE: all US cost estimates converted to CAN dollars using a 1.32 exchange rate.

Resource Cost Modeling
Step 2: Pro-Forma Financial Model

Resource Costs
Nova Scotia, 2019-2050

Capital Costs (Step 1) | O&M Costs | Fuel Prices

+

Resource Performance
Nova Scotia specific

Local Capacity Factors | Heat Rates | Degradation

+

Financing Assumptions
Based on NSPI Financing

NSPI Cost of Capital | Canadian Tax Incentives | Financing Terms

=

Levelized Cost Forecasts
Costs to NSPI, 2019-2050

Levelized Costs (Energy $/MWh, Capacity $/kW-yr)

Energy+Environmental Economics

Summary of proposed assumptions

Summary of Proposed Assumptions
Capital Costs (1 of 2) – Renewables and Storage

Technology	Subtechnology	Capital Cost (2019 CAD $/kW) 2019	2030	% Change
Wind	Onshore	$2,100	$1,959	-7%
	Offshore	$4,726	$3,340	-29%
Solar PV[a]	Tracking	$2,250	$1,803	-20%
Biomass	Grate	$5,300	$5,010	-5%
	Municipal Solid Waste	$8,470	$8,470	0%
Tidal	n/a	$10,000	$10,000	0%
Storage	Li-Ion Battery (1 hr)	$814	$410	-50%
	Li-Ion Battery (4 hr)	$2,325	$1,172	-50%
	Compressed air	$2,200	$2,200	0%
	Pumped Storage	$2,700	$2,700	0%

[a] Solar PV costs reported in $/kW-ac, reflecting an inverter loading ratio of 1.3

Summary of Proposed Assumptions

Capital Costs (2 of 2) – Fossil and Nuclear

		Capital Cost (2019 CAD $/kW)		
Technology	**Subtechnology**	**2019**	**2030**	**% Change**
Coal	Coal-to-gas conversion (102 – 320 MW)	$127 – 237	$127 – 237	0%
Natural Gas	Combined Cycle (145 MW)	$1,688	$1,609	-5%
	Combined Cycle w/ carbon capture and storage (145 MW)	$3,376	$3,101	-8%
	Combustion Turbine – Frame (50 MW)	$1,080	$1,031	-5%
	Combustion Turbine – Aero (50 MW)	$1,755	$1,676	-5%
	Reciprocating Engine (50 MW)	$1,823	$1,823	0%
Nuclear	Small modular reactor (100 MW)	$8,073	$7,731	-4%

Summary of Proposed Assumptions
Operating Costs – All Technologies

Technology	Subtechnology	Operating Cost Fixed O&M ($/kW-yr)	Operating Cost Variable O&M ($/MWh)
Wind	Onshore	$54	$0
	Offshore	$108	$0
Solar PV	Tracking	$20	$0
Biomass	Grate	$162	$7
	Municipal Solid Waste	$162	$0
Tidal	n/a	$338	$0
Storage	Li-Ion Battery (1 hr)	$8	$0
	Li-Ion Battery (4 hr)	$27	$0
	Compressed air	$20	$0
	Pumped Storage	$32	$0
Coal	Coal-to-gas conversion	$37-$45	$1
	Coal-to-biomass conversion	$152	$7
Natural Gas	Combined Cycle	$14	$3
	Combustion Turbine - Frame	$12	$7
	Combustion Turbine - Aero	$17	$7
	Reciprocating Engine	$27	$9
Nuclear	Small modular reactor	$203	$0

All O&M costs assumed to escalate at 2% per year.

Summary of Proposed Assumptions

Performance Assumptions

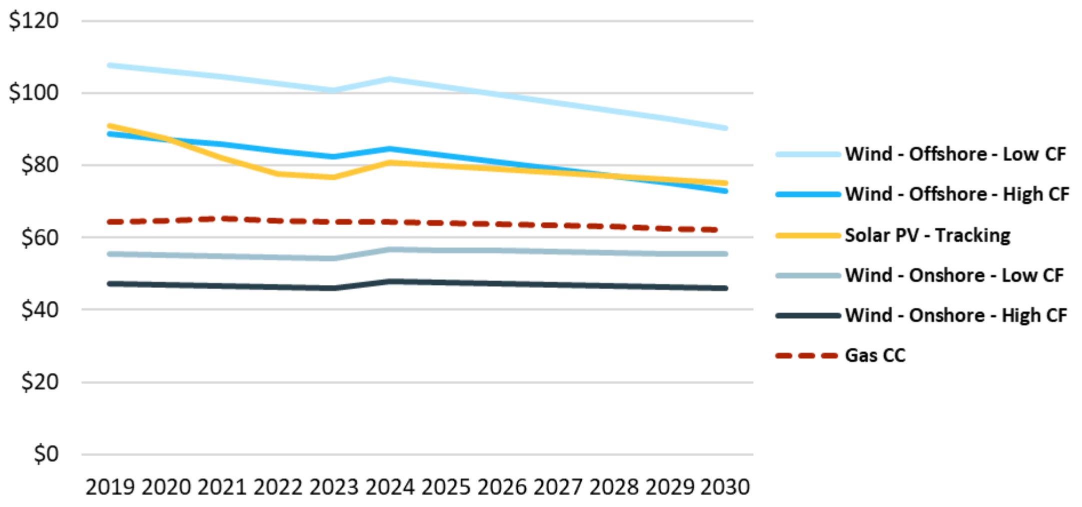
+ **Capacity factors for wind resources in Nova Scotia are based on CanWEA data**
  - Onshore wind: 35% to 41%, Offshore wind: 37% to 45%
+ **Capacity factors for solar resources in Nova Scotia are based on US NREL data**
  - Tracking solar: 15-19%
  - Solar assumed to have 30-degree tilt, fixed or single-axis tracking, and 1.3 inverter loading ratio
+ **An 85% capacity factor is assumed for biomass and an 80% capacity factor for municipal solid waste**
+ **A 26% capacity factor is assumed for tidal power**
+ **Storage round-trip efficiencies**
  - Li-ion: 87%, Compressed air: 70%, Pumped hydro: 80%

Summary of Proposed Assumptions

Future Resource Cost Competitiveness - Energy

+ **Onshore wind is least-cost resource today**
+ **Offshore wind remains expensive**
+ **Solar is not competitive without further cost decline**

Projected Levelized Cost of Energy in Nova Scotia (2019 CAD $/MWh)



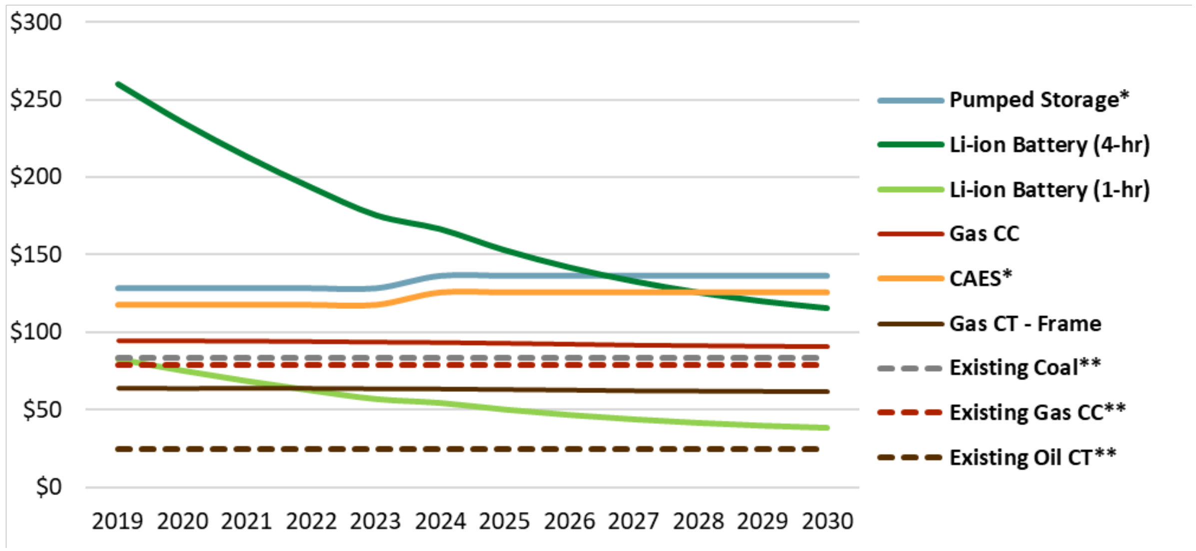
Source: E3 Analysis

Note: interconnection costs not included.

Summary of Proposed Assumptions
Future Resource Cost Competitiveness - Capacity

+ **Levelized capacity costs do not account for fuel/charging costs for storage**
+ **For long-duration capacity needs, gas CTs cheapest new resource today**
+ **Battery costs are forecasted to rapidly fall and be competitive for short duration capacity needs**
  - However, significant uncertainty still exists for current and future battery costs

Projected Levelized Cost of Capacity in Nova Scotia (2019 CAD $/kW-yr)



Source: E3 Analysis

* Pumped Storage and CAES costs and storage duration depend highly upon site conditions and are subject to significant uncertainty

** Existing units based on sustaining capex + fixed O&M. Sustaining capex in this study is based on the 2019 10 Year System Outlook's assumed sustaining capital forecast. For this study, these cost streams are levelized and fully collected over this horizon (2020-2029). In practice, NSPI's revenue recovery mechanism for long-lived assets depreciates the costs over longer time periods.

Summary of Proposed Assumptions
Resource Potential

+ Wind and solar

- Wind resource technical potential informed by CanWEA Wind Integration Study
- Solar resource technical potential informed by US NREL estimates
- Wind and solar resources subject to existing transmission limits
  - Renewables Stability Study (in-process) to inform IRP on costs of integrating more variable renewable energy

+ Other renewables

- Biomass 30 MW
- MSW: 50 MW
- Tidal: 300 MW

+ Natural gas

- Gas pipeline capacity may present a constraint to the number or type of gas plants that can be built

+ Coal repowering

- Only 3 units with existing pipeline supply considered for coal-to-gas

Details of resource options considered

Energy+Environmental Economics

Wind

Industry Trends: Historical Cost
Wind

+ **Wind project installation cost has declined since reaching a peak in 2010**
  - Average cost of projects installed in 2017 in US: **$1,610 USD/kW ($2,131 CAD/kW)**

Installed Wind Power Project Costs Over Time

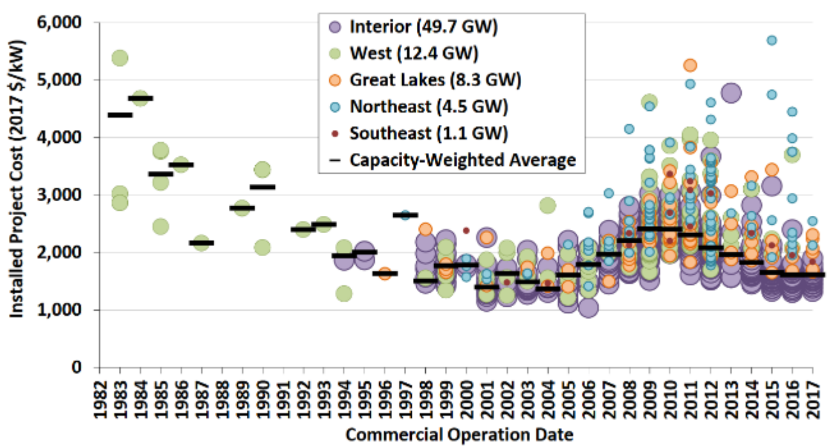
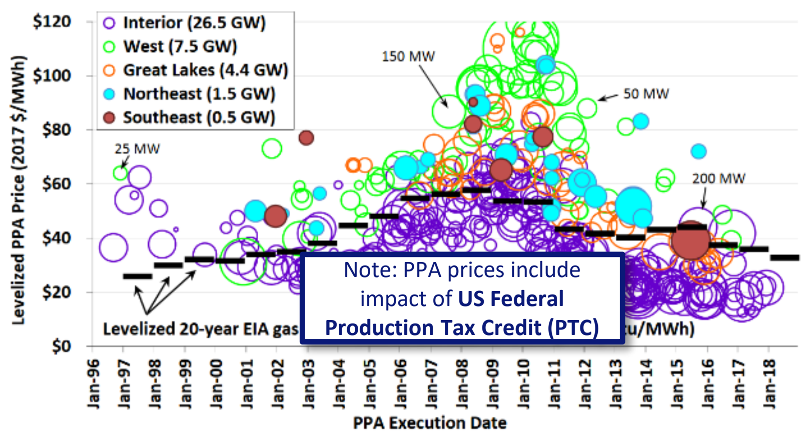


Figure source: 2017 Wind Technologies Market Report (LBNL)

Levelized Wind PPA Prices by PPA Execution Date



Note: PPA prices include impact of **US Federal Production Tax Credit (PTC)**

Figure source: 2017 Wind Technologies Market Report (LBNL)

Capital Cost Recommendations
Onshore Wind

+ **Wind costs vary significantly by region and terrain**
+ **Regions with higher capacity factors show slightly lower capital costs**
  - Captured in NREL's 10 techno-resource groups (TRG)
  - Nova Scotia wind costs estimated based on NREL TRG 5 (~40% CF for onshore wind)

	2019 Capital Cost		
Source	**US $/kW**	**CAN $/kW**	**Notes**
E3 WECC Survey (*link*)	$1,640	$2,179	Based on survey of Western US
New Brunswick IRP (*link*)	—	$2,456	2017 IRP used as regional index
NREL 2018 ATB (*link*)	$1,641	$2,180	Based on NREL TRG5 (40.7% CF)
E3 Recommendation	**—**	**$2,100**	**Lowers US estimates informed by NSPI engineering estimates**

Capital Cost Recommendations
Offshore Wind

- **Offshore wind is considerably less mature than onshore wind and subject to greater cost uncertainty and development risk**
- **Assumes fixed-bottom turbines for Nova Scotia**
  - Floating turbines significantly more expensive, only needed for water depths >50-60 meters
- **NREL's offshore wind costs do not reflect recent market trends**

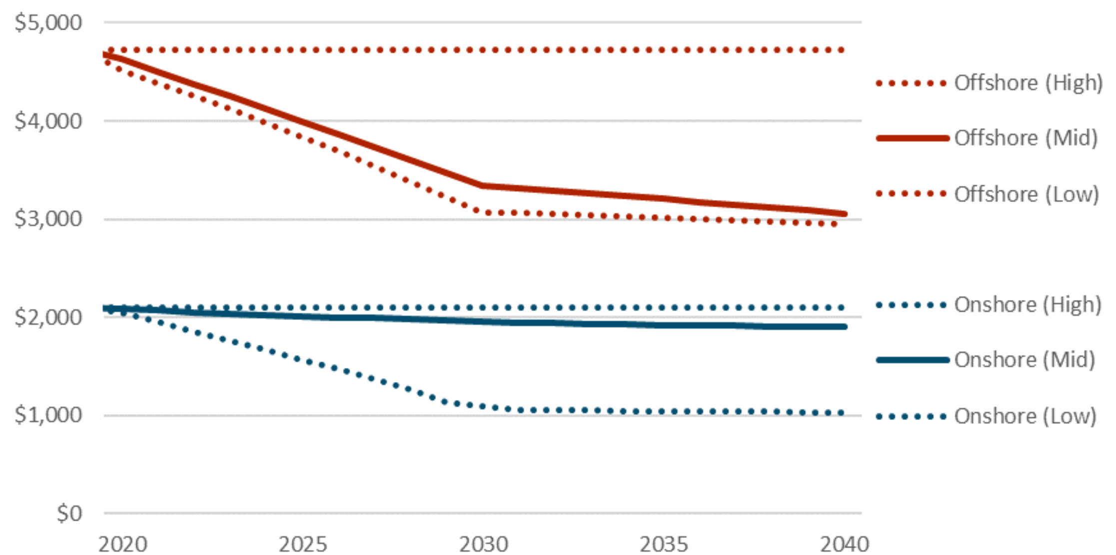
	2019 Capital Cost		
Source	**US $/kW**	**CAN $/kW**	**Notes**
E3 WECC Survey (*link*)	$3,570	$4,726	Based on survey of Western US
New Brunswick IRP (*link*)	—	—	2017 IRP used as regional index
NREL 2018 ATB (*link*)	$4,568	$6,047	Based on NREL TRG4 (41% CF)
E3 Recommendation	**—**	**$4,726**	**Use WECC survey**

Future Cost Reductions
Wind

+ Wind costs will continue to decline in future

- Further improvements in physical scale (hub height, blade length) will increase efficiency
- Offshore capital cost declines very likely, onshore cost declines less likely
- NREL ATB mid case (onshore TRG 5, offshore TRG 4) used for capital cost reduction trajectory
  - High and low scenarios available for sensitivities
  - NOTE: WECC cost survey also uses NREL cost trajectories

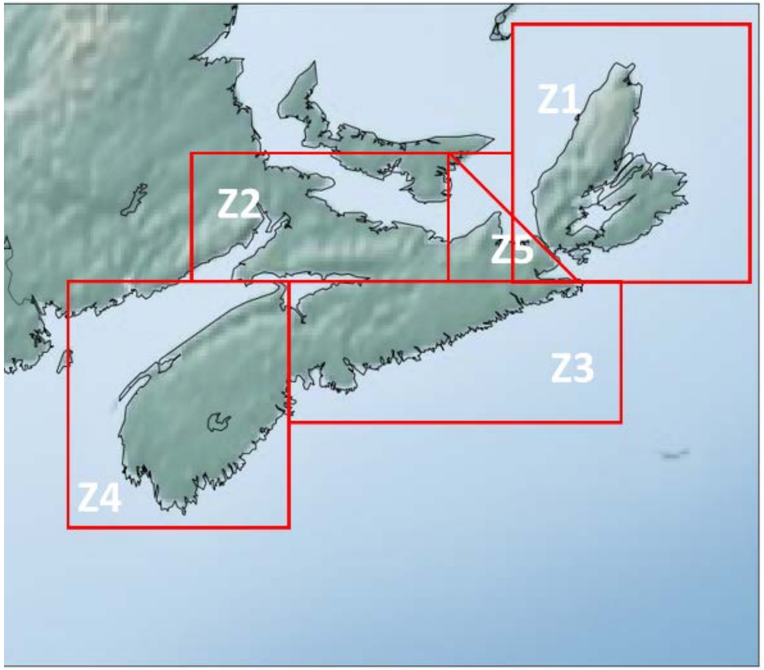
Wind Capital Cost Reductions (2019 CAN $/kW)



Source: WECC, NREL, E3 Analysis

Performance Assumptions and Resource Potential
Wind

+ **To estimate capacity factors, E3 used the CanWEA pan-Canada wind integration study**
  • Modeled current and possible future wind plants in Nova Scotia (171 wind sites in province)
+ **5 development zones align with solar development zones (based on NREL's NSRDB)**
+ **Little variation in CF across Nova Scotia**
+ **1,000 MW of potential assumed per zone (500 onshore / 500 offshore)**
  • Potential will be updated based on Renewables Stability Study that will inform grid constraints and investments required to integrate larger amounts of new renewables



	Total Capacity (GW)	# Total Sites	# Offshore Sites	Avg. CF: Offshore	Avg. CF: Onshore	Avg. CF: Overall
Zone 1	16.4	89	7	41%	38%	38%
Zone 2	1.0	17	3	39%	37%	37%
Zone 3	3.6	23	19	45%	39%	43%
Zone 4	1.0	10	7	42%	41%	41%
Zone 5	5.0	32	6	40%	38%	38%

Financing and Operating Assumptions

Wind

Financing:

- Financing lifetime: 25 years
- Cost of equity: 9.00%
- Cost of debt: 5.54%
- Debt ratio: 62.5%
- Pre-tax WACC: 6.84%
- Tax rate: 31%
- Depreciation:
  - Class 43.2 Advanced CCA (50%) to 2019
  - Class 43.1 CCA (30%) thereafter
  - Implemented tax measures from 2018 federal government economic update

Operating costs

- Onshore fixed O&M: $54/kW-yr
  - 2% annual escalation
- Offshore fixed O&M: $108/kW-yr
  - 2% annual escalation
- Variable O&M: $0/MWh

Levelized Cost of Energy Results
Wind

- Onshore wind LCOE relatively stable
- Significant decline in offshore wind LCOE by 2030

Year	LCOE (2019 CAD $/MWh)			
	Onshore		Offshore	
	Low CF 37%	High CF 41%	Low CF 39%	High CF 45%
2020	$55	$47	$106	$87
2030	$55	$46	$90	$73
2040	$54	$44	$83	$67

Note: Low and High CFs represent range from zone-based Nova Scotia sites in CanWEA testing database

Utility Scale Solar PV

Industry Trends: Historical Cost
Utility-Scale Solar PV

- **Continued declines in module pricing and balance of system costs have led to installed system costs approaching USD $1/W-dc in 2018**
  - Premium associated with tracking technology has nearly disappeared
- **With impact of US ITC, recent PPA prices for higher quality solar resources have ranged between USD $20-$40/MWh**

NREL Utility-Scale PV System Cost Benchmark Summary (Inflation Adjusted), 2010-2018

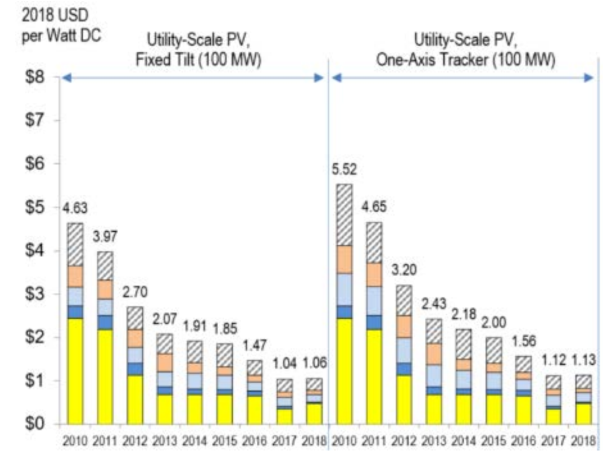


Figure source: US Solar Photovoltaic Cost Benchmark: Q1 2018 (NREL)

Levelized PPA Prices by Region, Contract size, and PPA Execution Date: 2014-2018

Note: PPA prices include impact of **US Federal Investment Tax Credit (ITC)**

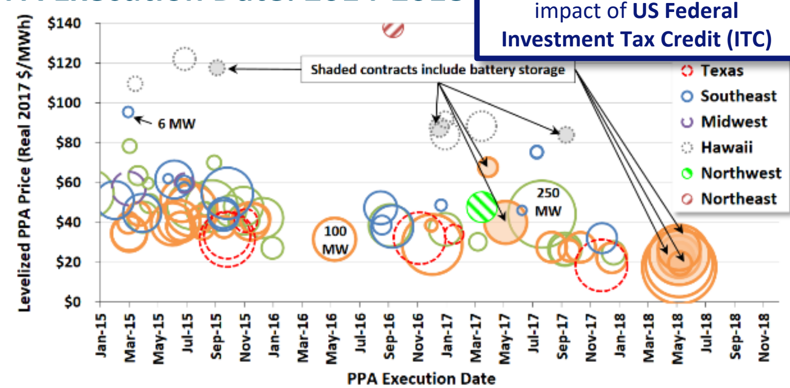


Figure source: Utility-Scale Solar 2018 (LBNL)

Industry Trends: System Design

Utility-Scale Solar PV

+ **The inverter loading ratio (ILR) reflects the ratio between the DC rating of modules and the AC rating of the system's inverters**
  - Design choice is a tradeoff between increased system cost and improved performance (i.e. higher capacity factor)

- With reductions in module costs, increasing ILRs (i.e. oversizing module arrays) to improve capacity factor has become industry standard
- Median ILR for new systems is **1.3**

Trends in Inverter Loading Ratio by Mounting Type and Installation Year

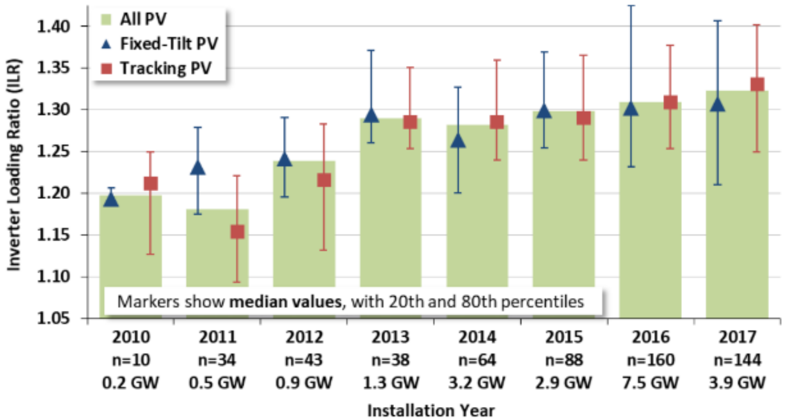


Figure source: Utility-Scale Solar 2018 (LBNL)

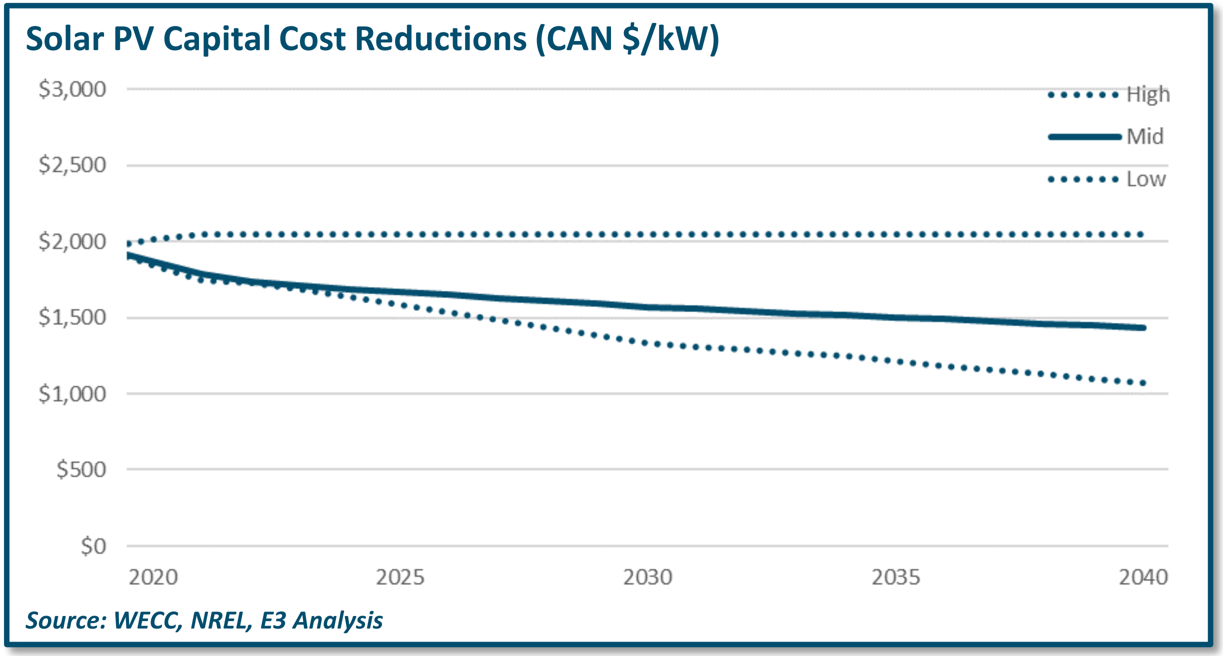
Capital Cost Recommendations
Utility-Scale Solar PV

+ **Utility-scale PV projects now almost exclusively single-axis tracking**
  - Tracking solar provides increased capacity factor for little to no premium in capital costs
  - Only tracking solar considered
+ **WECC costs adjusted per local labor costs, terrain, and other factors, informed by NSPI internal estimates**

	2019 Capital Cost		
Source	**US $/kW-ac**	**CAN $/kW-ac**	**Notes**
E3 WECC Survey (*link*)	$1,479	$1,958	Based on survey of Western US
New Brunswick IRP (*link*)	—	$2,620	2017 IRP used as regional index
NREL 2018 ATB (*link*)	$1,449	$1,917	NREL annual technology baseline
E3 Recommendation	**—**	**$2,250**	**WECC, 2019 + local cost adjustment**

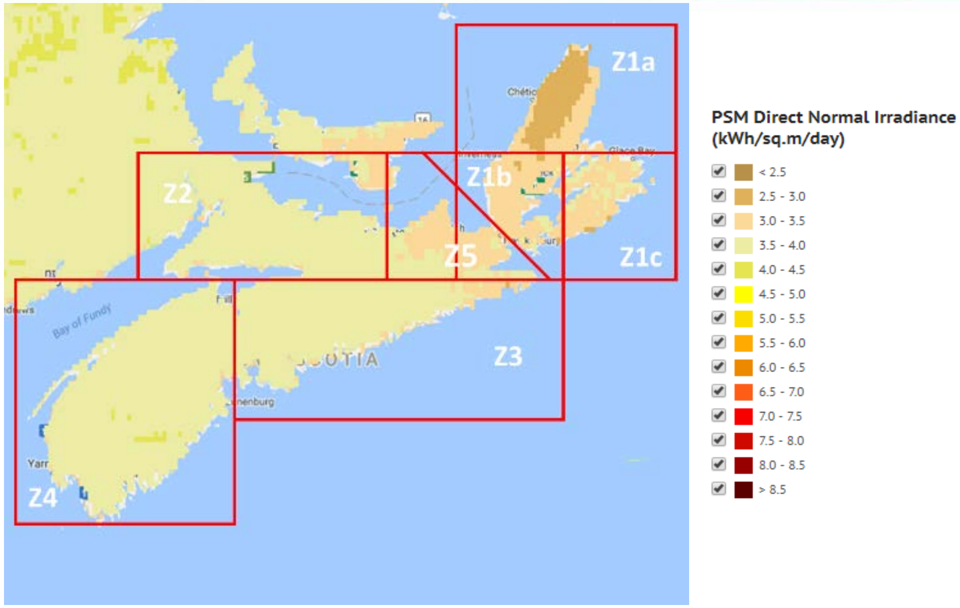
Future Cost Reductions
Solar PV

+ **Solar PV costs will continue to decline in future, driven by technology development, soft cost declines, and learning effects**
  - NREL 2018 ATB (mid case) used for capital cost reduction trajectory
    - High and low scenarios available for sensitivities
    - NOTE: WECC cost survey also uses NREL cost trajectories



Solar Methodology

- **Data from NREL's National Solar Radiation Database (NSRDB)**
- **Assumptions:**
  - Invertor loading ratio = 1.3
  - Tilt = 30 degrees
  - Single-Axis Tracking
- **CF developed by resource zone**
  - Range from 15-19%
- **500 MW of potential assumed per zone**
  - Potential will be updated based on Renewables Stability Study that will inform grid constraints and investments required to integrate larger amounts of new renewables



Zone	Tracking: Avg. CF
1a	15%
1b	16%
1c	18%
2	18%
3	18%
4	19%
5	17%

Financing and Operating Assumptions
Utility-Scale Solar PV

+ Financing:

- Financing lifetime: 25 years
- Cost of equity: 9.00%
- Cost of debt: 5.54%
- Debt ratio: 62.5%
- Pre-tax WACC: 6.84%
- Tax rate: 31%
- Depreciation:
  - Class 43.2 Advanced CCA (50%) to 2019
  - Class 43.1 CCA (30%) thereafter
  - Implemented tax measures from 2018 federal government economic update

+ Operating costs

- Fixed O&M: $20/kW-yr
  - 2% annual escalation
- Variable O&M: $0/MWh

Levelized Cost of Energy Results
Utility-Scale Solar PV

+ **Solar relatively expensive given Nova Scotia's limited resource**
  - However, costs will continue to decline

	LCOE (2019 CAD $/MWh)	
Year	Low CF (15%)	High CF (19%)
2020	$111	$87
2030	$95	$75
2040	$87	$68

Energy+Environmental Economics

Other renewables

Capital Cost Recommendations
Biomass

+ **NSPI understands biomass regulations limit the amount of forest biomass available to attain any renewable electricity standard to 350,000 dry tonnes/annum**
+ **Biomass project capital costs are typically location specific**

	2019 Capital Cost		
Source	**US $/kW**	**CAN $/kW**	**Notes**
E3 WECC Survey (*link*)	$4,488	$5,941	Based on survey of Western US
New Brunswick IRP (*link*)	—	$5,713	2017 IRP used as regional index
NREL 2018 ATB (*link*)	$4,019	$5,321	NREL annual technology baseline
E3 Recommendation	**—**	**$5,300**	**Informed by NSPI engineering estimates**

Financing, Operating, and Performance Assumptions

Biomass

+ Financing:

- Financing lifetime: 35 years
- Cost of equity: 9.00%
- Cost of debt: 5.54%
- Debt ratio: 62.5%
- Pre-tax WACC: 6.84%
- Tax rate: 31%
- Depreciation:
  - Class 43.2 Advanced CCA (50%) to 2019
  - Class 43.1 CCA (30%) thereafter
  - Implemented tax measures from 2018 federal government economic update

+ Performance:

- 85% capacity factor assumed
- 13,500 Btu/kWh heat rate

+ Operating costs

- Fixed O&M: $162/kW-yr
  - 2% annual escalation
- Variable O&M: $7/MWh
  - 2% annual escalation

+ Fuel

- Based on existing biomass fuel costs
- Approx. $60/MWh

Levelized Cost of Energy Results

Biomass

- **LCOE of biomass almost does not change from 2020 to 2040 due to slow reduction in capital costs**

	LCOE (2019 CAD $/MWh)
Year	Biomass
2020	$140
2030	$141
2040	$140

Capital Cost Recommendations
Municipal Solid Waste

+ **Municipal solid waste capital costs are typically location specific**

	2019 Capital Cost		
Source	**US $/kW**	**CAN $/kW**	**Notes**
E3 WECC Survey (***link***)	—	—	Based on survey of Western US
New Brunswick IRP (***link***)	—	$11,427	2017 IRP used as regional index
E3 Recommendation	**—**	**$8,470**	**Informed by NSPI engineering estimates**

Financing, Operating, and Performance Assumptions

Municipal Solid Waste

Financing

- Financing lifetime: 35 years
- Cost of equity: 9.00%
- Cost of debt: 5.54%
- Debt ratio: 62.5%
- Pre-tax WACC: 6.84%
- Tax rate: 31%
- Depreciation:
  - Class 43.2 Advanced CCA (50%) to 2019
  - Class 43.1 CCA (30%) thereafter
  - Implemented tax measures from 2018 federal government economic update

Performance

- 80% capacity factor assumed
- 18,000 Btu/kWh heat rate

Operating costs

- Fixed O&M: $162/kW-yr
  - 2% annual escalation
- Variable O&M: $0/MWh

Fuel

- $5/MMBtu assumed

Levelized Cost of Energy Results

Municipal Solid Waste

- **Slight capital cost increases due to changes in depreciation schedule**

Year	LCOE (2019 CAD $/MWh) Municipal Solid Waste
2020	$167
2030	$171
2040	$171

Capital Cost Recommendations
Tidal

- **NSPI has been a global leader in developing tidal power**
  - Annapolis Tidal Power Plant was the first tidal plant in North America
  - E3 recommends using NSPI capital cost estimate
- **However, tidal power is still an expensive technology with limited commercial deployment**
  - Recent failure of OpenHydro highlights the challenge of the tidal power industry

	2019 Capital Cost		
Source	US $/kW	CAN $/kW	Notes
New Brunswick IRP (*link*)	—	$8,643	2017 IRP used as regional index
E3 Recommendation	**—**	**$10,000**	**Informed by NSPI engineering estimates**

Financing, Operating, and Performance Assumptions

Tidal

+ Financing:

- Financing lifetime: 35 years
- Cost of equity: 9.00%
- Cost of debt: 5.54%
- Debt ratio: 62.5%
- Pre-tax WACC: 6.84%
- Tax rate: 31%
- Depreciation:
  - Class 43.2 Advanced CCA (50%) to 2019
  - Class 43.1 CCA (30%) thereafter
  - Implemented tax measures from 2018 federal government economic update

+ Operating costs

- Fixed O&M: $338/kW-yr
  - 2% annual escalation
- Variable O&M: $0/MWh

+ Performance:

- 26% capacity factor assumed

Levelized Cost of Energy Results
Tidal

+ **Tidal power is a relatively expensive resource option**
  - Driven by very high capital and O&M costs

	LCOE (2019 CAD $/MWh)
Year	Tidal
2020	$344
2030	$359
2040	$359

Energy+Environmental Economics

Battery Storage

Industry Trends: Historical Cost

Battery Storage

- **Innovation in battery technology, driven mainly by transportation applications, has led to recent dramatic declines in costs to produce lithium-ion batteries**
  - Since 2010, year-on-year declines of 8-35% have been observed

- **Future stationary applications of battery technology will benefit from cost reductions driven by transport applications**

BNEF Lithium-Ion Battery Price Survey, 2010-18 (2018$/kWh)

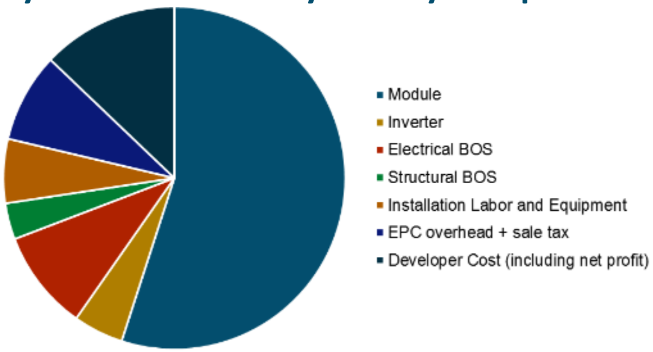
Note: reported prices reflect cell & pack costs for transportation applications

Figure source: Lithium-ion Battery Prices (BNEF)

Lithium-ion battery cost breakdown by power capacity and duration

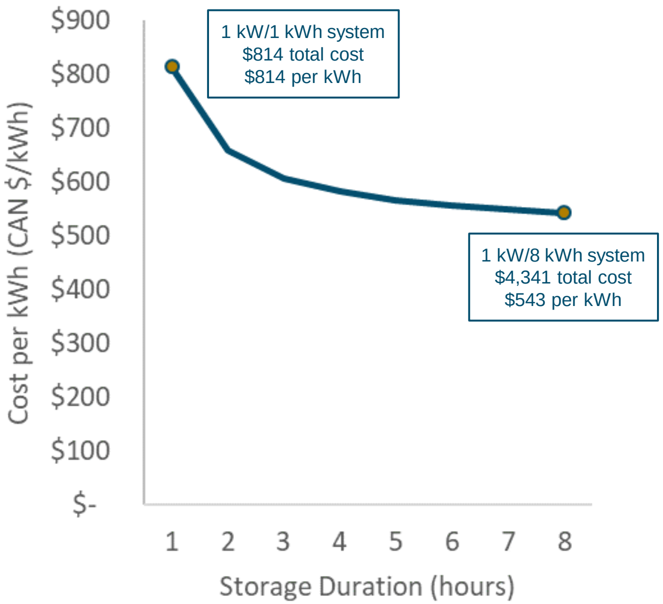
+ **Battery costs vary significantly by system specifications**
+ **For modeling purposes, costs are commonly broken into two categories**
  - Costs that scale with *power* ("capacity"), quoted in \$/kW
  - Costs that scale with *energy* ("duration"), quoted in \$/kWh
+ **Battery modules are the largest and best understood component of system cost and the one that scales most linearly with duration**
+ **Fixed capacity cost including inverter and interconnection vary significantly by project**
+ **Longer duration batteries cheaper per MWh of storage due to spreading of fixed costs**

Utility-scale 4-hr Battery Cost by Component



Source: E3 Analysis

Utility-scale Battery Cost per kWh by Duration



Source: E3 Analysis

Capital Cost Recommendations
Battery Storage

- **Costs estimates vary widely due to early stage of technology and differences in scale and arrangement**
  - Speed of price decline makes estimates quickly outdated
- **Costs per kWh also depend on duration of battery system**
- **High end of Lazard range utilized per local labor costs, terrain, and other factors, informed by NSPI internal estimates**

	2019 Capital Cost		
Source	**US $/kW-ac**	**CAN $/kW-ac**	**Notes**
E3 WECC Survey (*link*)	$536	$709	Cost estimate for 1-hr battery
E3 WECC Survey (*link*)	$1,530	$2,025	Cost estimate for 4-hr battery
Lazard LCOS 3.0 (*link*)	$1,338 - $1,700	$1,771 - $2,250	Cost range for 4-hr battery (2017)
Lazard LCOS 4.0 (*link*)	$1,163 - $1,850	$1,540 - $2,450	Cost range for 4-hr battery (2018)
E3 Recommendation	**—**	**$814**	**Recommended cost for 1-hr battery**
	—	**$2,325**	**Recommended cost for 4-hr battery**

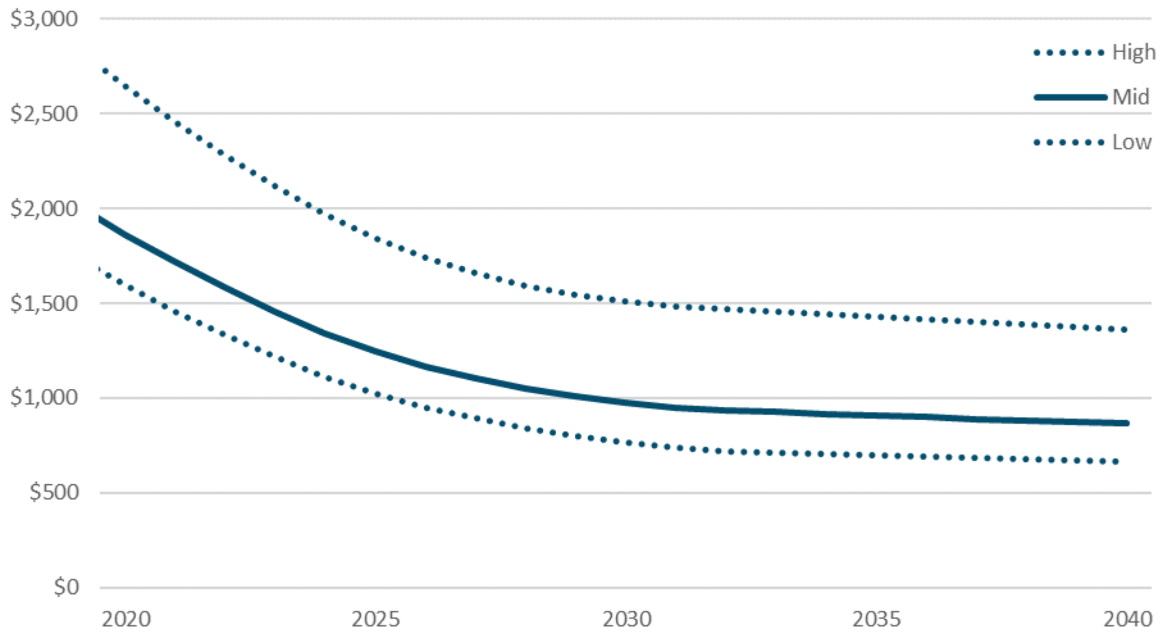
Costs that scale with power ("capacity")	**$310**	**Recommended capacity $/kW**
Costs that scale with energy ("duration")	**$504**	**Recommended energy $/kWh**

Future Cost Reductions

Battery Storage

+ **Future battery cost projections are modeled based on Lazard's Levelized Cost of Storage v.4.0**
  - Forecast is highly uncertain due to emerging status of industry
  - There is variation in current costs, but industry sources predict continued cost declines (driven by expanding electric vehicle market)

Storage Cost Projection – 4-hr Battery ($/kW)



Source: Lazard, E3 Analysis

Financing, Operating, and Performance Assumptions

Battery Storage

+ **Financing:**
  - Financing/depreciation lifetime: 20 years
  - Cost of equity: 9.00%
  - Cost of debt: 5.54%
  - Debt ratio: 62.5%
  - Pre-tax WACC: 6.84%
  - Tax rate: 31%
  - Depreciation:
    - Class 17 – 8% DB in 2017
    - Step up to Class 43.2 Advanced CCA (50%) in 2018-2019
    - Class 43.1 CCA (30%) thereafter
    - Implemented tax measures from 2018 federal government economic update

+ **Round trip efficiency: 87% (based on Lazard LCOS 4.0, *link*)**

+ **Operating costs (4-hr battery)**
  - Fixed O&M: $27/kW-yr
    - 2% annual escalation
  - Variable O&M: $0/MWh

+ **Li-ion cost adders**
  - Extended warranty: 1.5% of total capital cost, annually starting in Year 3
  - Augmentation charge: 3.3% of energy (kWh) cost component, annually

Levelized Fixed Cost Results

Battery Storage

- Short duration battery is competitive with NG plants on a capacity basis
- Larger decrease in cost by 2030 as technology matures

	Levelized Fixed Cost (2019 CAD $/kW-yr)	
Year	1-hr Battery	4-hr Battery
2020	$75	$236
2030	$38	$116
2040	$33	$101

Energy+Environmental Economics

Compressed Air

Capital Cost Recommendations

Compressed Air

- **Compressed air costs are highly site-specific and can vary considerably based on the characteristics of the site (geology, etc.)**
- **Few recent commercial projects adds to cost uncertainty**
- **E3 recommendation informed by NSPI engineering estimates**

	2019 Capital Cost		
Source	**US $/kW**	**CAN $/kW**	**Notes**
E3 WECC Survey (*link*)	$2,142	$2,836	Based on survey of Western US
New Brunswick IRP (*link*)	—	$2,073	2017 IRP used as regional index
Pacificorp IRP (*link*)	$1,658	$2,194	Broad range of size and duration
E3 Recommendation	**—**	**$2,200**	**Reflects lower regional estimates vs. WECC survey**

Financing, Operating, and Performance Assumptions

Compressed air

+ Financing:

- Financing lifetime: 35
- Cost of equity: 9.00%
- Cost of debt: 5.54%
- Debt ratio: 62.5%
- Pre-tax WACC: 6.84%
- Tax rate: 31%
- Depreciation: Class 17 – 8% DB
- Implemented tax measures from 2018 federal government economic update

+ Operating costs

- Fixed O&M: $20/kW-yr
  - 2% annual escalation
- Variable O&M: $0/MWh
  - 2% annual escalation

+ Round trip efficiency: 70%

+ Emissions:

- CAES utilizes gas turbine during operations
- E3 recommends a 4000 Btu/kWh heat rate for CAES output

Levelized Fixed Cost Results

Compressed air

- Slight capital cost increases due to changes in depreciation schedule
- Fuel cost of natural gas is an additional cost for CAES
- More competitive for longer duration storage

Year	Levelized Fixed Cost (2019 CAD $/kW-yr) Compressed air
2020	$118
2030	$125
2040	$125

Energy+Environmental Economics

Pumped Storage

Capital Cost Recommendations
Pumped Storage

+ **Pumped storage costs are highly site-specific and can vary considerably based on the characteristics of the site**
+ **For a generic facility cost estimate, E3's recommended Nova Scotia cost estimate is generally lower than other generic point estimates**
  - Informed by NSPI engineering estimates

	2019 Capital Cost		
Source	**US $/kW**	**CAN $/kW**	**Notes**
E3 WECC Survey (*link*)	$2,397	$3,173	Based on survey of Western US
New Brunswick IRP (*link*)	—	$7,369	2017 IRP used as regional index
Pacificorp IRP (*link*)	$2,734 - $3,320	$3,619 - $4,395	Broad range of size and duration
E3 Recommendation	**—**	**$2,700**	**Informed by NSPI engineering estimates**

Financing, Operating, and Performance Assumptions

Pumped Storage

+ Financing

- Financing lifetime: 50
- Cost of equity: 9.00%
- Cost of debt: 5.54%
- Debt ratio: 62.5%
- Pre-tax WACC: 6.84%
- Tax rate: 31%
- Depreciation*:
  - Class 43.2 Advanced CCA (50%) to 2019
  - Class 43.1 CCA (30%) thereafter
  - Implemented tax measures from 2018 federal government economic update

+ Round trip efficiency: 80%

+ Operating costs

- Fixed O&M: $32/kW-yr
  - 2% annual escalation
- Variable O&M: $0/MWh

* Depreciation rate is dependent upon size of installation.

Levelized Fixed Cost Results
Pumped Storage

+ **Pumped storage may be competitive for longer duration storage**
  - Cost estimates depend on long financing lifetime (50 years) for high initial capital cost

Year	Levelized Fixed Cost (2019 CAD $/kW-yr) Pumped Storage
2020	$128
2030	$136
2040	$136

Energy+Environmental Economics

Coal Repowering

Repowering Options
Coal Repowering

+ Coal-to-gas

- Only 3 coal units with firm natural gas supply assumed for coal-to-gas
- Costs informed by NSPI engineering estimates

Coal Unit	Capacity	Capital Cost (2019 CAN $)	Capital Cost (2019 CAN $/kW)	Notes
Point Tupper Unit 2	102	$24.2 M	$237/kW	150 MW today, however natural gas pipeline capacity constraints are believed to limit output to 102 MW
Trenton Unit 5	155	$24.4 M	$157/kW	If only unit 5 repowered
Trenton Unit 6	165	$24.4 M	$148/kW	If only unit 6 repowered
Trenton Unit 5+6	320	$35.5 M	$127/kW	If units 5+6 both repowered

+ Impact of federal regulations

- Federal regulations limiting carbon dioxide emissions from natural gas-fired generation of electricity specify performance standards, which limit the allowable operating life of any repowered coal unit

Financing and Operating Assumptions

Coal Repowering

+ Financing:

- Financing lifetime: 8
  - Estimate for illustrative purposes
- Cost of equity: 9.00%
- Cost of debt: 5.54%
- Debt ratio: 62.5%
- Pre-tax WACC: 6.84%
- Tax rate: 31%
- Depreciation: Class 17 – 8% DB

+ Operating costs

Technology	Fixed O&M ($/kW-yr)	Escalation	Variable O&M ($/MWh)	Escalation
Coal-to-Gas: Point Tupper Unit 2	$45	2%	$1.32	2%
Coal-to-Gas: Trenton Unit 5	$37	2%	$1.48	2%
Coal-to-Gas: Trenton Unit 5	$37	2%	$1.48	2%

Repowering Options
Coal Repowering

+ Coal-to-biomass

- Costs informed by NSPI engineering estimates for cost of retrofitting Trenton Unit 5 to co-fire woody biomass at 20% of plant capacity
  - Retrofitted plant would operate as 120 MW coal / 30 MW biomass
- NSPI understands biomass regulations limit the amount of forest biomass available to attain any renewable electricity standard to 350,000 dry tonnes/annum.
  - Given this constraint, and NS Power's Port Hawkesbury biomass power generation plant, it is assumed that a repowered coal/biomass co-fire facility (80%/20%) could meet current regulations, subject to conditions in the Renewable Electricity Regulations.

Coal Unit	Capacity	Capital Cost (2019 CAN $)	Capital Cost (2019 CAN $/kW)	Notes
Trenton Unit 5	30 MW (20% of total net MW)	$39.3 M	$1,313/kW	Informed by NSPI engineering estimate

Levelized Fixed Cost Results
Coal Repowering

+ **Coal-to-gas shows average of three units considered**

Technology	Levelized Fixed Cost (2020 CAD $/kW-yr)
Coal-to-Gas	$67
Coal-to-Biomass (20% co-firing)	$360

Energy+Environmental Economics

Natural Gas

Capital Cost Recommendations
Natural Gas Generation (1 of 2)

+ **E3 generally recommends using the WECC Cost Survey for gas plant cost**

Technology	Source	Capital Cost (2019 CAN $/kW)	Notes
Combined Cycle (145 MW)	E3 WECC Survey (*link*)	$1,688	Based on survey of Western US
	New Brunswick IRP (*link*)	$1,974	2017 IRP used as regional index
	NREL 2018 ATB (*link*)	$1,441	NREL annual technology baseline
	E3 Recommendation	$1,688	
Combined Cycle w/ carbon capture and storage (145 MW)	E3 WECC Survey (*link*)	$3,376	Based on survey of Western US
	NREL 2018 ATB (*link*)	$2,979	NREL annual technology baseline
	E3 Recommendation	$3,376	

Capital Cost Recommendations

Natural Gas Generation (2 of 2)

+ **E3 generally recommends using the WECC Cost Survey for gas plant cost**

Technology	Source	Capital Cost (2019 CAN $/kW)	Notes
Combustion Turbine – Frame (50 MW)	E3 WECC Survey (***link***)	$1,080	Based on survey of Western US
	New Brunswick IRP (***link***)	$1,252	2017 IRP used as regional index
	NREL 2018 ATB (***link***)	$1,226	NREL annual technology baseline
	E3 Recommendation	$1,080	Based on WECC Survey
Combustion Turbine – Aero (50 MW)	E3 WECC Survey (***link***)	$1,755	Based on survey of Western US
	New Brunswick IRP (***link***)	$1,693	2017 IRP used as regional index
	E3 Recommendation	$1,755	Based on WECC Survey
Reciprocating Engine (50 MW)	E3 WECC Survey (***link***)	$1,823	Based on survey of Western US
	E3 Recommendation	$1,823	

Cost Components
Natural Gas Generation

+ **E3's proposed capital costs include the following cost components for new natural gas plants:**
    - Overnight capital cost
    - Construction financing
    - Nominal interconnection costs (i.e. a short gen-tie line)
+ **O&M costs include:**
    - Insurance, taxes, land lease payments, and other fixed costs
    - Annualized large component replacement costs over the technical life
    - Scheduled and unscheduled maintenance
+ **CCS capital costs include the cost of capturing and compressing the CO2, but not delivery and storage to a storage reservoir or industrial site for use**
    - $4.76/MWh added to VOM to account for transport and storage costs
        - Assumes CAN $13/ton CO2 transported (Rubin et al, 2015) and 0.36 tons/MWh captured (90% capture rate at 7.53 Btu/MWh heat rate)

Financing and Operating Assumptions

Natural Gas Generation

+ Financing:

- Financing lifetime: 20
- Cost of equity: 9.00%
- Cost of debt: 5.54%
- Debt ratio: 62.5%
- Pre-tax WACC: 6.84%
- Tax rate: 31%
- Depreciation: Class 17 – 8% DB

+ Operating costs

Technology	Fixed O&M ($/kW-yr)	Escalation	Variable O&M ($/MWh)	Escalation
Combined Cycle	$14	2%	$3	2%
Combined Cycle w/ carbon capture and storage	$45	2%	$3	2%
Combustion Turbine – Frame	$12	2%	$7	2%
Combustion Turbine – Aero	$17	2%	$7	2%
Reciprocating Engine	$27	2%	$9	2%

Levelized Fixed Cost Results
Natural Gas Generation

+ **Combustion turbine is least-cost source of capacity in each year of forecast**

	Levelized Fixed Cost (2019 CAD $/kW-yr)				
Year	Combined Cycle	Combined Cycle w/ CCS	Combustion Turbine – Frame	Combustion Turbine – Aero	Reciprocatin g Engine
2020	$94	$206	$64	$101	$114
2030	$91	$193	$62	$97	$114
2040	$88	$183	$60	$94	$114

Energy+Environmental Economics

Small Modular Nuclear

Industry Trends: State of the Market

Small Modular Nuclear

- **Small modular reactors (SMR) have been proposed as an alternative to large-scale nuclear facilities**
  - Concept = replace economies of scale in size with economies of scale in manufacturing (i.e. cost savings from producing many small modular reactors)
  - Size per reactor ranges from 50-300 MW
- **Various technologies in R&D phase**
- **No technology has been commercialized**

Sample SMR Design (Hitachi's 300 MW BWRX-300)

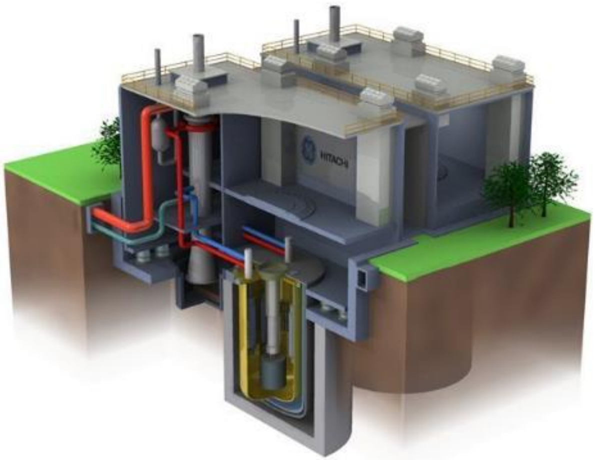


Figure source: Power Engineering Magazine

Capital Cost Recommendations

Small Modular Nuclear

- **High uncertainty of costs given nascent technology**
  - Capital cost estimates vary by 2-3x
  - Low cost estimates unlikely until SMR industry scales up manufacturing capacity
  - Recent US nuclear projects have been over-budget and delayed (~$11,000+/kW)
- **E3 recommends reliance on a broadly used public data source (such as NREL ATB)**
- **High/low cost sensitivities can be explored using other data sources (if desired)**

	2019 Capital Cost		
Source	**US $/kW**	**CAN $/kW**	**Notes**
New Brunswick IRP (*link*)	—	$11,691	2017 IRP, SMR specific estimate
Pacificorp IRP (*link*)	$6,149	$8,140	12 SMRs (570 MW net capacity)
Energy Innovation Reform Project, Adv. Nuclear Cost Analysis, 2018 (*link*)	$4,013	$5,313	Survey of industry-provided cost estimates for advanced nuclear, including SMRs (avg. shown, range was ~CAN $2,900-8,200)
NREL 2018 ATB (*link*)	$6,099	$8,073	Advanced nuclear
E3 Recommendation	**—**	**$8,073**	

Financing and Performance Assumptions

Small Modular Nuclear

+ **Financing:**
  - Financing lifetime: 30 years
  - Cost of equity: 9.00%
  - Cost of debt: 5.54%
  - Debt ratio: 62.5%
  - Pre-tax WACC: 6.84%
  - Tax rate: 31%
  - Depreciation: Class 17 – 8% DB

+ **Capacity factor: 90%**

+ **Operating costs**
  - Fixed O&M: $203/kW-yr
    - 2% annual escalation
  - Variable O&M: $0/MWh
    - 2% annual escalation

+ **Fuel costs**
  - Uranium: $0.86 / MMBtu
    - From NREL ATB

Levelized Cost of Energy Results
Small Modular Nuclear

+ **Small Modular Nuclear is very expensive compared to other resources**

	LCOE (2019 CAD $/MWh)
Year	Small Modular Nuclear
2020	$589
2030	$573
2040	$553

Thank You

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ADDENDUM TO SUPPLY OPTIONS STUDY: COSTS FOR EXISTING ASSETS

JULY 31, 2019

Nova Scotia POWER
An Emera Company

OVERVIEW

- The following provides preliminary high level cost projections for the existing supply side assets on the NS Power system.
- NS Power anticipates the Modeling Plan and Assumptions will include scenarios and/or sensitivities around these assumptions.
- Further detailed unit cost and operating assumptions will be provided in the Assumptions Development phase prior to modeling.
- The team will provide current updates to these parameters during the Assumptions Development phase of the IRP.

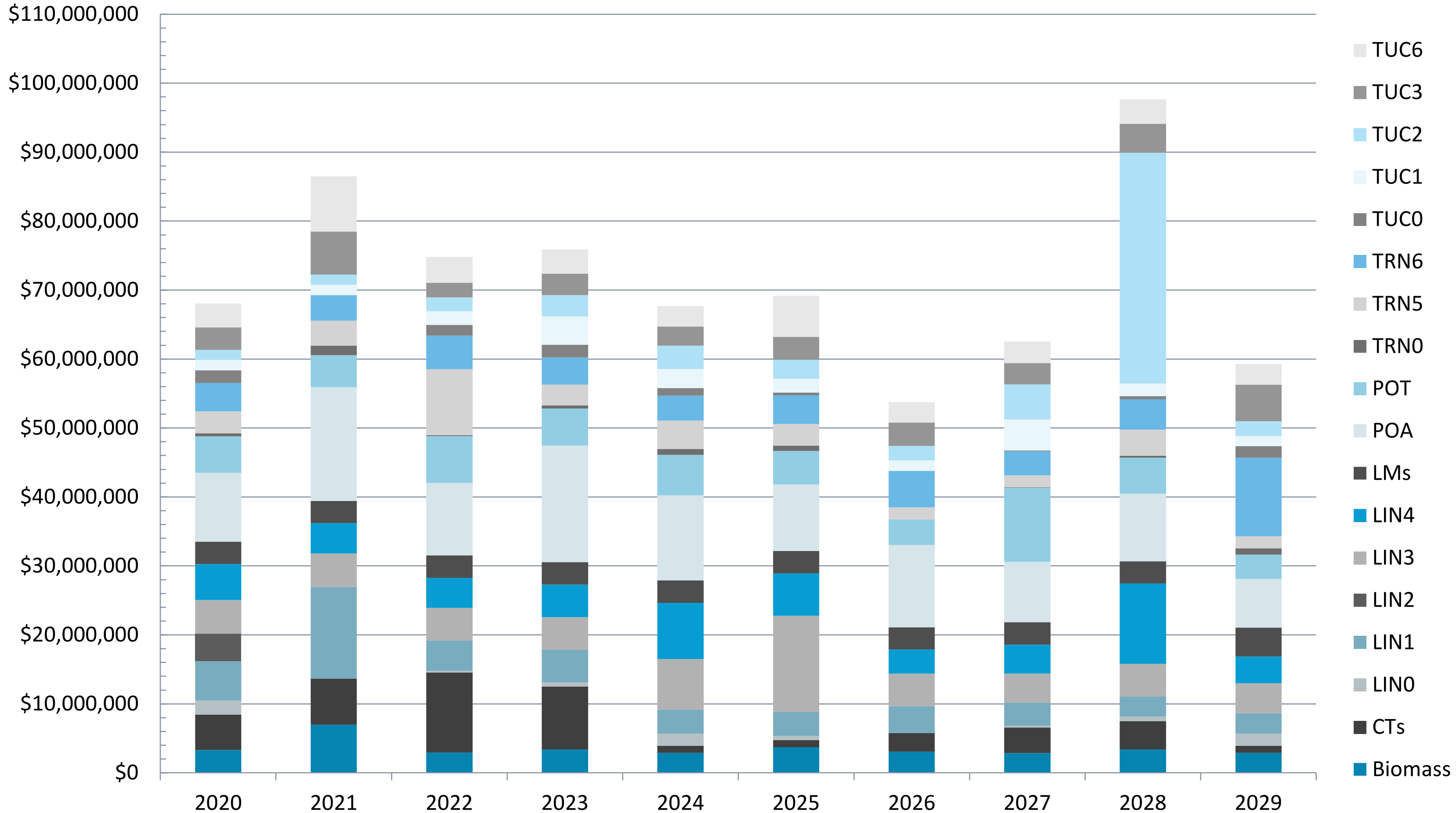
SUSTAINING CAPITAL FORECAST: BACKGROUND

- The sustaining capital forecast is developed based upon the expected utilization of the assets. The most recent cost forecast is from the 2019 10 Year System Outlook Report.

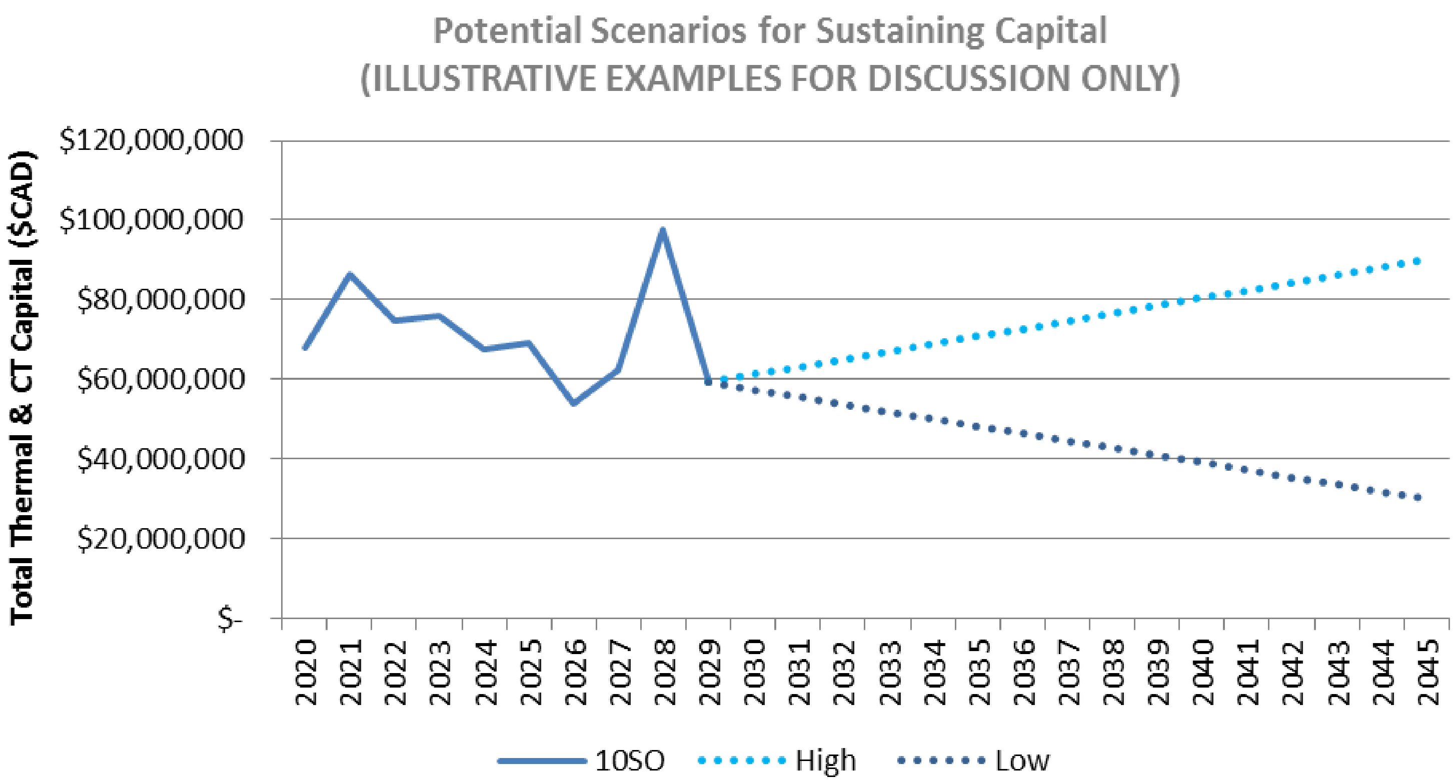
- During the 2019 ACE Proceeding, NS Power conducted a Hydro Asset Study to estimate the costs of sustaining and decommissioning small hydro assets on the NS system. These costs, with updates as applicable, will be used as the cost assumptions for existing small hydro.

- Scenarios for sustaining capital (for example, different utilization factors driving different investment profiles) around sustaining capital, particularly in the longer term where uncertainty is increased, will be developed in collaboration with stakeholders through the Modeling Plan and Assumptions Development phases.

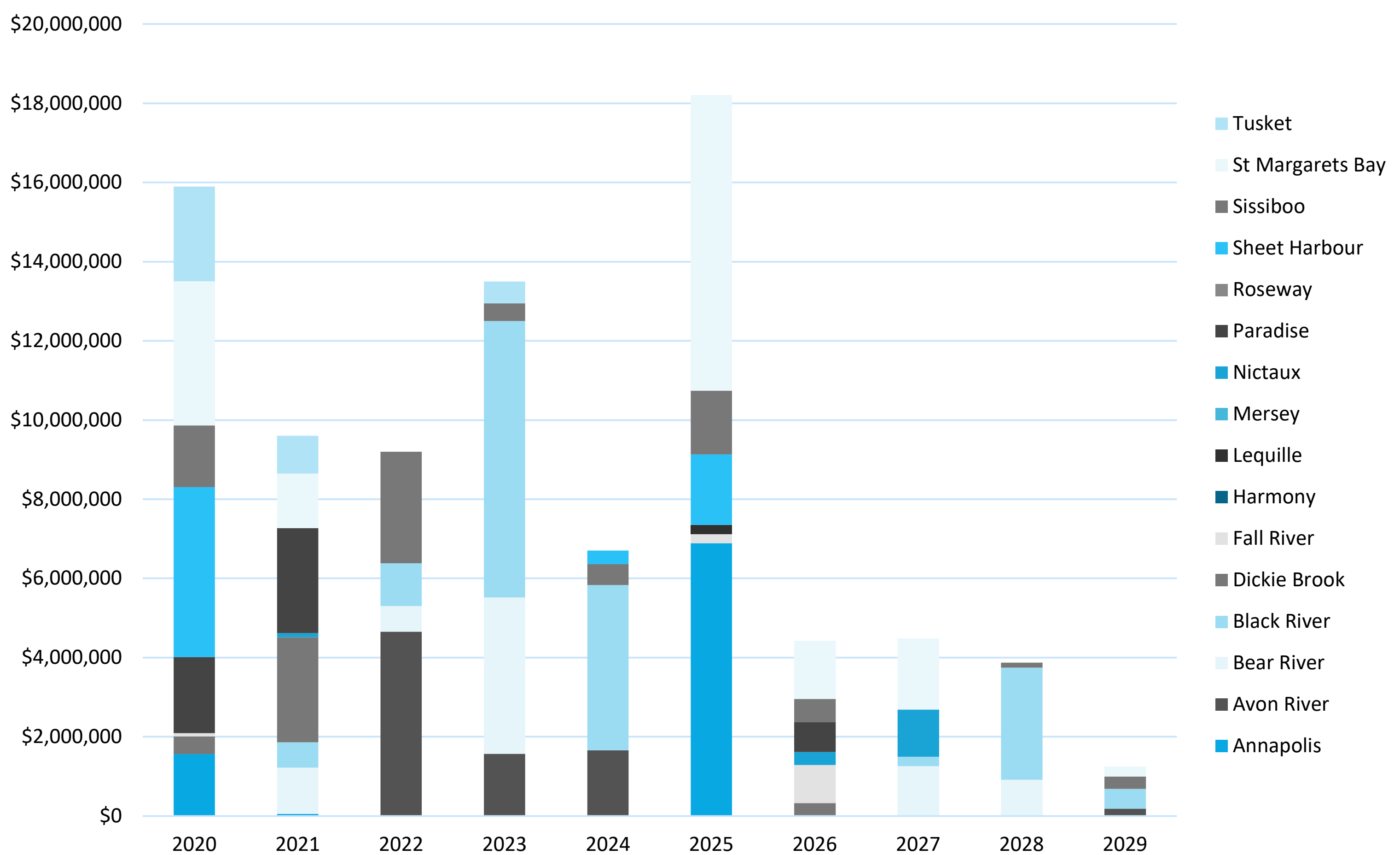
SUSTAINING CAPITAL FORECAST: THERMAL & CTS



SUSTAINING CAPITAL FORECAST: THERMAL & CTS



SUSTAINING CAPITAL FORECAST: HYDRO ASSET STUDY



Nova Scotia POWER
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Specialist Consultants
to the Electricity Industry

Nova Scotia Power Stability Study for Renewable Integration

Report

Prepared By: PSC North America

Khosro Kabiri

For: Nova Scotia Power Inc.

Date: July 24, 2019

PSC Job Ref.: JC7643

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ABBREVIATIONS

AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery Energy Storage Systems
DC	Direct Current
EMT	Electromagnetic Transient
EPRI	Electric Power Research Institute
FCAS	Frequency Control Ancillary Service
FFR	Fast Frequency Response
HVDC	High Voltage Direct Current
IE	Republic of Ireland
kV	kilo Volt
LSI	Largest Single Infeed
MW	Megawatt
MVA	Mega volt ampere
NB	New Brunswick
NI	Northern Ireland
NS	Nova Scotia
NSPI	Nova Scotia Power Inc.
NS-UARB	Nova Scotia Utility and Review Board
POI	Point of Interconnection
RMS	Root Mean Square
RoCoF	Rate of Change of Frequency
SA	South Australia
SC	Synchronous Condenser
SCRIF	Short Circuit Ratio with Interaction Factor
STATCOM	Static Synchronous Compensator
UFLS	Under Frequency Load Shedding
UK	United Kingdom

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Executive Summary

Background Scene

Policies related to sustainable energy sources are driving the decarbonization of the energy mix. The technologies available for harnessing energy from sustainable sources and integrating these sources into existing power grids rely heavily on the use of power electronics. Wind and solar generation have proven to be the most cost-effective choices so far and have been deployed in many geographic regions, depending on the availability of local natural sources of energy. This move is observed as a clear shift from conventional synchronous generation (steam, hydro, combustion turbine) to power electronic device driven generation (wind, solar, battery energy storage) dominating the scene. The design and development concept of the power grid is based on conventional generating units providing inertia with rotating mass and system technical performance in terms of voltage and frequency stability was based on that concept. Therefore, the move toward a power electronic dominated power grid is expected to change the dynamic behavior of the power system [1].

System stability is a loosely used collective terminology that defines the overall level of system behavior within the context of integration of power electronic based generation. In terms of sustainable energy sources, the question then is the limit of power electronic based generation that can be accommodated in the system with impacting various system technical performance parameters. These cover transient voltage stability, frequency stability, short-circuit current levels, voltage waveform quality, voltage fluctuation and so on. Addressing system stability issues often results in Ancillary or Grid Services to be required. Depending on system characteristics, some systems experience part of the issues in a more prominent way than others and some can be resolved by relatively simple means under specific conditions. However, in general, with increased penetration of power electronic interfaced energy sources, all power systems will experience some form of change in their dynamic behavior with reduced system inertia, reduced system strength and possible interaction between the remaining synchronous machines on synchronizing and damping torque components [1]. Power quality is also a system characteristic that is influenced by this shift.

Study Objective

The objective of this study is to assess the integration of increased levels of renewable generation in Nova Scotia and to form recommendations for reinforcement and/or for further investigations required to enable this integration.

The Nova Scotia power system like any other power system is limited in its ability to accommodate an increasing number of power electronic interfaced generation. The specific limitations are due to its size, level of demand and limited interconnection with neighboring systems. The most challenging issues are its ability to export excess power to neighboring systems via the existing ties and to survive in an islanded mode following the loss of the AC ties.

This study looks into the possibility of increasing the levels of generation from renewables but more specifically from wind sources in Nova Scotia from the current installed capacity of 600 MW. Different renewable sources of energy have different intermittency characteristics. However, regardless of the primary source of energy (wind, solar, tidal, etc.), inverter-based generation has similar dynamic characteristics as viewed from the electrical grid, and this dynamic characteristic is different from that of a synchronous generator. Increasing intermittent inverter-based generation beyond this point in Nova Scotia while removing thermal units from system dispatch represents a challenge which needs to be addressed by careful consideration of many different aspects. These include system transient stability, regulation reserve to compensate for wind and load fluctuations, frequency control of Nova Scotia in islanded operation, keeping the short circuit levels sufficiently high, and preferably expanding the export market. It is noted that the trend observed in the Nova Scotia system - that inverter-based generation displaces conventional forms of generation - is seen in other jurisdictions around the world as well. Two examples, one from Australia (South Australia power system) and one from Europe (Irish power system) are given as comparative background information due to their similarities to the Nova Scotia system as well as PSC's system knowledge and involvement in those jurisdictions.

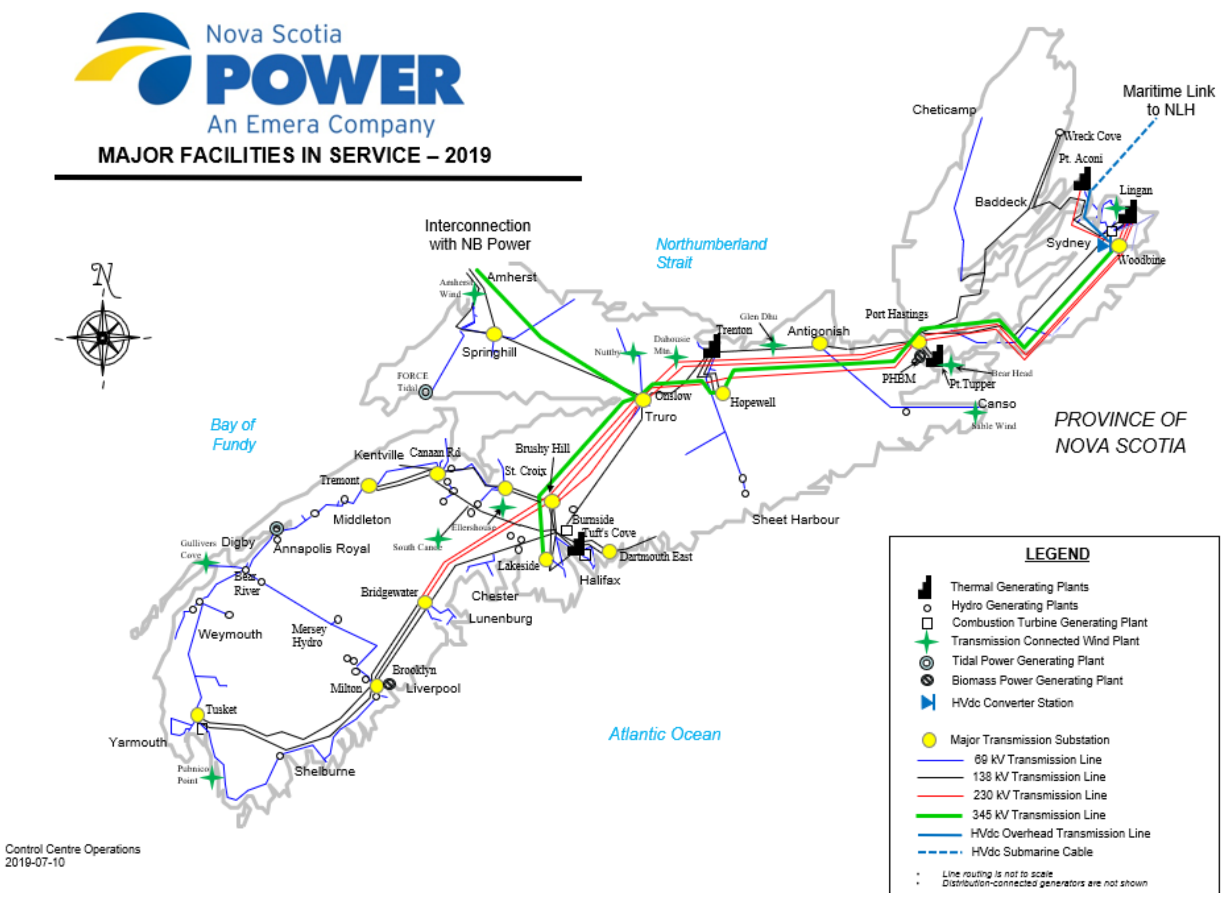
The main driver behind this study has been the directive issued by the Nova Scotia Utility and Review Board (NS-UARB) regarding the need for such a study:

> *"Establish requirements to allow increased levels of wind on the NSPI system. Two threshold criteria to allow increased levels of cost-effective wind resources are completion of a second 345 kV intertie to New Brunswick, and assessment of NSPI's Provincial transmission system and related support services (to maintain stability and voltage criteria). NSPI should determine, with specificity, the set of technical improvements required to allow different increments of additional wind on their system. This should include the effect of additional transmission capacity to New Brunswick, the presence of the Maritime Link, and the ability to further increase wind penetration through transmission grid reinforcement. This should also recognize that the introduction of bulk scale battery storage as a possible capacity resource that can provide co-benefits associated with stability and voltage support."*

Study Approach and Methodology

There are two main components to this study: the first is an initial glimpse into the aforementioned international experience from Australia and Ireland in order to draw comparisons to the Nova Scotia system. This identifies the challenges other systems have, the metrics used to measure the adequacy of the system to support increasing levels of variable renewable generation, and the solutions that have been suggested or tried. The second component of the study mainly comprises transient stability simulations, but also other means of analysis performed on the Nova Scotia system model to establish an understanding of the particular technical issues that Nova Scotia has to deal with. The analysis allows for recommendations for system reinforcements and for further investigations in order to integrate an increased level of renewable generation in Nova Scotia.

The following map shows the major generation and transmission facilities in Nova Scotia. An HVDC link connects Nova Scotia to Newfoundland. Nova Scotia is also connected through two AC links (345-kV and 138-kV) to New Brunswick. The energy import and export happen through these two links. In addition to scheduled flow, these links provide for emergency supply. The reserve capacity allocated to the links is an important part of secure operation of the interconnected grid. As the renewable generation capacity increases at a faster pace than the demand in Nova Scotia, excess generation above what the system requires or is able to accommodate, will become a more frequent occurrence. This excess generated power must be exported or curtailed[1]. This economical tradeoff is studied in resource planning exercises such as an Integrated Resource Plan.



As the map shows, the transmission connected wind farms are spread throughout the province. This study has found that for some of the wind farms the short circuit levels are marginally low. For the wind farms that

[1] Curtailment could be an economic option if the cost of upgrades to permit low or no curtailment operation exceed the benefits of the curtailment reduction.

are close to online thermal generating plants the short circuit level at the point of interconnection to the grid is generally higher than for those which are remote from online large synchronous machines. However, if the thermal units are retired or dispatched off this advantage fades away. The inverter-based generators typically use the voltage at the Point of Interconnection (POI) to synchronize with the grid. When the short circuit ratio at the POI is very low, during faults in the system the voltage measurement will become erroneous, and it can cause the wind farm to become unstable resulting in the tripping of the farm or control system oscillations. This is especially a problem in the South Australia system due to a large geographic area and long transmission lines with wind farms clustered together remote from synchronous machines. One way to remedy this situation is to install synchronous condensers in close proximity to the wind farms.

Increasing the transfer levels on the ties and retiring of synchronous generators in correlation to bringing on more renewable generation in Nova Scotia poses another challenge; the frequency stability of the grid. The major event of interest in this regard is tripping of the AC ties to New Brunswick and islanding of Nova Scotia which causes large frequency excursion (over-frequency or under-frequency) in Nova Scotia. At present under-frequency load-shedding is relied upon for mitigation, but this creates its own problems as the shed load needs to be restored and raises reliability and reputational concerns. This challenge is more pronounced in Nova Scotia in comparison to the other two systems referenced in this report, i.e. South Australia and Ireland (due to the relatively smaller size, and hence lower online inertia, of the NS system as compared to SA or Ireland but with comparable largest single contingency on a percentage basis).

Study Criteria

Historically, generation in power systems consisted mainly of synchronous machines with high inertia, such as thermal units. As a result, most disturbances in the system were not able to cause large frequency excursions. However, as more conventional generators are being retired and replaced by inverter-based generators, the frequency excursions in the system have become more extreme.

Conventional power systems operate around a narrow frequency band (60 Hz in North America). When the frequency deviates from the nominal frequency, several unwanted effects happen and the automatic controllers in the system act to bring it back to the nominal value. There are both fast and slow controllers in the system that are sensitive to frequency changes. Under frequency load shedding is a fast remedial action which sheds some load if the frequency dips and stays below a certain threshold. In Nova Scotia one scenario that causes this to happen is when the AC ties are tripped while importing power from New Brunswick. The higher is the import prior to tripping, the bigger the frequency dip will be.

The main question that was answered by the simulations in this study was if the Nova Scotia system, upon disconnecting from the AC interconnection or losing one DC pole, will be able to survive the transients and remain stable. In addition, several other contingencies internal to Nova Scotia were simulated.

The criteria checked for each simulation were:

- No cascade generator or transmission line tripping
- No loss of synchronism
- Frequency maintained with the frequency fault ride-through envelope
- Voltage at generator connection points maintained within the voltage fault ride-through envelope
- No thermal overloads on lines
- Fault current levels sufficient to operate transmission and distribution protection
- Short circuit ratio maintained for wind farm points of interconnection

It should be noted that transient stability simulation looks into the behavior of the system a few seconds immediately after a disturbance in the system. Wind variations in longer time frames of minutes or hours are known to also have an impact on the stability of the system and need to be properly considered. However, this study did look into the regulation reserves needed to accommodate increased levels of wind generation.

Another impact of inverter-based generation is that it reduces the short circuit level in the system. This has a negative impact on transmission system protection[2] as the relays do not see the same level of currents flowing during short circuit events and might not isolate the affected part of the system in time to protect the equipment. From the viewpoint of the inverter-based generator, very low short-circuit levels might cause its controllers to mal-function. Therefore, it is important to maintain a minimum level of short circuit ratio at wind farm locations.

Study Results

This study showed that 600 MW of wind generation can be handled by the existing system under a variety of system load and conditions studied. This conclusion was arrived at by considering different metrics such as the short circuit ratios at wind farm points of interconnection to the grid, regulation reserve needed to compensate for wind fluctuations, and mainly by performing transient stability simulations. In these simulations the Nova Scotia system was stressed by maximizing wind MW output and reducing the number of synchronous generators online.

Next, simulations were performed with different system reinforcements and increased wind levels. It was found that a second 345-kV AC transmission line to New Brunswick will allow wind generation to be increased close to 1000 MW. The loss of the existing 345 kV tie is a major contingency for the Nova Scotia

[2] More of an issue for distance protection. Differential protection is less susceptible to maloperation due to low fault levels.

system and inclusion of this second tie brings system security and flexibility in terms of operating the system.

In the third batch of studies, synchronous condensers and battery storage systems were added into the Nova Scotia power system as an alternative to adding the second 345-kV AC tie to New Brunswick. This study found that at 1000 MW wind level, a 200-MVA synchronous condenser and a 200-MW battery storage with fast ramping capability will be enough to reduce the under-frequency load shedding to two stages (out of six) in case of losing the AC tie to New Brunswick. It is important to note that the investigation looked only at the addition of these two technologies without the second New Brunswick tie. Both these options require further study.

Interpretation of Results

To be able to rely on the protection systems that have been successfully operating in the system for decades it is important to keep a certain amount of rotating inertia online. The study concluded that for the existing system, Nova Scotia should have at least three thermal units online so that in case of islanding it can come back to a new stable steady state operating condition. Translating this into an online minimum system inertia value is possible and a figure is provided, however, to refine this figure, further studies covering a variety of dispatch scenarios is required. Minimum thermal limits were set based on the loss of a single tie to New Brunswick, with limited support from Maritime Link and no support from wind generation. Therefore, the second tie eliminates the primary rationale behind the minimum online thermal units. However, other services are required for the system which are provided by the thermal units regardless of the second tie option. Those services include:

- Balancing services (tie-line control) to manage fluctuations in load and renewable generation (wind, solar).
- Load following, a longer-term generation control service to manage load pickup from overnight to daytime loads
- Short circuit current and voltage control at a local level (perhaps provided with a combination of synchronous condensers and the second tie).

The addition of a second tie will push the possible level of wind generation to 1000 MW and will also bring about enhanced system security and stability as it avoids islanding of Nova Scotia in the event of losing a single AC tie. A similar increase in wind capacity can be achieved with the introduction of synchronous condensers and battery storage; however, with this option islanding of Nova Scotia, and subsequent load or generator shedding and challenges with frequency control in islanded operation will not be addressed.

Adding synchronous condensers has three major benefits. First, they stay online during short circuit events and contribute to the short circuit current therefore improving the short circuit ratio. Second, they add to the online inertia in the system, so the frequency excursion magnitudes and rates of change reduce. Third, synchronous condensers have a fast voltage controller that can regulate the voltages in the system.

Batteries also bring several advantages in general. Like synchronous condensers they help with regulating the voltage. However, being inverter-based they do not contribute to the short circuit ratio. Batteries can compensate for the power imbalance caused by a transmission tie trip or a generator or load trip event rapidly, up to their power capability. Simulations done with both batteries and synchronous condensers in this study show that the load shedding can be effectively reduced. The batteries also help with the more long-term task of regulation with intermittent wind power.

The study results indicate that for the scenarios studied, the contribution of the synchronous condenser to the online inertia in Nova Scotia in islanded operation cannot reduce the load shedding amount by a significant amount. Hence, a combination of batteries and synchronous condensers seem to provide a better technical solution (however, still not better than a second tie to avoid islanding for the same contingencies). Introduction of synchronous condensers by retro fitting existing synchronous generators that are planned to be decommissioned has been considered as a possible option in some systems. The choice between such conversion as opposed to a new standalone procurement and installation needs to be made based on project delivery, technical requirements and limitations, and cost-benefit analysis.

Observations from the Study

The current study has utilized only a limited but representative number of system scenarios. The analysis shows the possibility of an increased wind capacity especially with the inclusion of the second tie to New Brunswick. However, more dispatch scenarios will need to be studied or at least checked in order to establish a more robust level of renewable penetration.

Time domain simulations using RMS quantities, such as done in this study, have known limitations. By expanding the studies into electromagnetic time domain, it is possible to establish a more technically robust behavior from the power electronic device controls, which in turn may increase the level of renewables that can be accommodated.

The study has not specifically looked into the provisions of grid code requirements. This is an area other jurisdictions have taken forward especially with regard to the expectations for renewable sources, provisions like synthetic inertia to name one.

Implications on power quality requirements have also not formed part of the analysis conducted. Introducing larger volumes of power electronic devices into the system has known adverse effects with regards to, for example, harmonic distortion levels on the system.

Conclusions and Recommendations

The study results suggest that the existing Nova Scotia power system can support the existing 600 MW of wind generation. In the current state, in order to stay secure for the loss of the New Brunswick tie, at least 3 thermal units are required to be online. Even with this measure, when the tie is importing, a large amount of customer load needs to be shed to recover the system frequency during such an event.

The development of the second 345 kV tie to New Brunswick (Onslow to Salisbury) allows the integration of a further 400MW of wind generation (system installed total of 1000 MW inverter-based generation). Furthermore, it provides an enhanced level of system reliability and security for the Nova Scotia system across a range of operating conditions including storm events.

The same level of wind generation can be reached with the deployment of synchronous condensers and BESS. However, to avoid all stages of load shedding to be activated following trip of the existing tie to New Brunswick when importing, the synchronous condenser and BESS need to be large (judged by comparison to such installations in other jurisdictions). A 200 MVA synchronus condenser fitted with flywheel and a 200 MW BESS reduce the load shedding to 2 stages out of 6. This option also lacks the ancillary reliability benefits afforded by the second 345kV tie line.

Study results indicate that the tie to New Brunswick is of the highest significance to the stability of the NS Power system as the loss of the tie dictates most of the planning and/or operational actions. Strenthening of this tie with a second 345 kV line becomes crucial and should be considered as the first alternative to explore before the introduction of other technological solutions or in tandem with them. Application of synchronous condenser and BESS in addition to the second tie line, would result in more benefits such as an increase in renewable generation and enhanced system security and flexibility.

In concluding, within the scope of the studies performed in preparing this report, it is recommended that the existing study should be expanded to establish a system security level commensurate with increased wind generation. The defined topology should include the second tie as a starting position so that intuitive studies to establish maximum renewable generation penetration with minimum system reinforcement can be established.

Further recommendations beyond the introduction of the second tie include:

- Expand the existing study to check wider system dispatch scenarios and establish requirements in terms of support.
- Perform enhanced studies in EMT area to support technical requirement.
- Establish how the requirements can be met, such as service provision via specific investments or via grid code changes.
- Commission parallel studies to check other areas of possible technical limitations such as power quality.

1. Introduction

As part of the move to more sustainable electrical energy sources, there is a growing trend in shifting the production of electrical energy to more carbon free sources. Harnessing sustainable and renewable energy sources and then integrating these into power networks is mainly achieved through the use of power electronic devices with different electrical performance characteristics when compared to synchronous machines.

A key aspect of this shift from synchronous generation to power electronic device driven generation, is the expected change in the dynamic behavior of the power system that will have an impact on the various stability characteristics that define technical limits of operation. Many factors are expected to affect the way this proliferation influences the operability of the system, for example smaller systems may require more stringent performance requirements, introduction of new technology or services while others can accommodate this change to a level with no substantial change.

The main technical aspects associated with the integration of power electronic converter-based generation concentrate around voltage and frequency stability issues, reduced system strength, effect of loads and potential interaction issues. Issues associated with voltage stability are due to lack of reactive power provision or demand (demand issue due to the loads being fed by distributed sources). On the frequency stability side, the lack of inertia is earmarked to be the major issue as it has been observed to increase the rate of change of frequency following system disturbances. Furthermore, in systems where priority is given to reactive power rather than active power in terms of control, frequency issues due to lack of active power injection have been observed following voltage dips on the systems. Reduced system strength is expected to bring several new issues such as the lack of enough short circuit current to trigger protection systems, mis-operation of phase-locked-loop controllers and commutation failures of line commutated converters due to increased chance of voltage depression. Loads with constant power characteristics drawing an increased current under reduced system strength with the voltage depressed will also add to the ongoing technical issues. Finally, oscillation due to resonances and especially at sub-synchronous frequencies is being envisaged as a further limitation to be caused by the introduction of control interactions.

The Nova Scotia power system has experienced a steady growth of wind generation through the years with the total installed wind capacity in 2018, reaching just over 600 MW. This steady growth, relative to the size of the system, is partly due to the requirements introduced for Nova Scotia to have a more diverse energy mix, reaching 40% renewable energy by 2020 and partly due to the take up of community owned wind generation projects as part of Community Feed-in Tariff introduced back in 2011. The 600 MW level was thought to be at or near the limit of economic wind integration into the Nova Scotia Power system without any system upgrades. Therefore, the need arose to revisit the situation and to study and investigate if 600 MW can indeed be supported by the current system conditions, and in addition to look into the possibilities of increasing the wind penetration level in Nova Scotia beyond the potential limit.

The current work was therefore commissioned and executed as a result of the directive issued by the Nova Scotia Utility and Review Board (NS-UARB) which states that the study should:

> *"Establish requirements to allow increased levels of wind on the NSPI system. Two threshold criteria to allow increased levels of cost-effective wind resources are completion of a second 345 kV intertie to New Brunswick, and assessment of NSPI's Provincial transmission system and related support services (to maintain stability and voltage criteria). NSPI should determine, with specificity, the set of technical improvements required to allow different increments of additional wind on their system. This should include the effect of additional transmission capacity to New Brunswick, the presence of the Maritime Link, and the ability to further increase wind penetration through transmission grid reinforcement. This should also recognize that the introduction of bulk scale battery storage as a possible capacity resource that can provide co-benefits associated with stability and voltage support."*

This report sets out to explain the studies performed in order to establish the level of power electronic converter-based generation that can be accommodated on the Nova Scotia power system as is and by considering the developments suggested in the above directive.

It is worth noting that the upward trend of conventional generation being displaced with inverter-based generation is not unique to Nova Scotia and other electric power systems are facing similar challenges. High level comparative information for two such systems are provided in the report due to PSC having specific knowledge about these two systems and their similarities to the Nova Scotia electric power system.

The following sections describe the methodology used in this study along with the assumptions made. Information for the Nova Scotia power system is provided in more detail including power flow, dynamics, and contingency models.

Observations from the transient stability simulations and an overview of studies and issues from two other jurisdictions (South Australia and Ireland) are discussed in order to draw parallels and/or jurisdictional best practices.

It is important to note that the term "wind" or "wind generation" is used interchangeably with renewable energy sources and the generic conclusions would also apply to other power electronic interfaced generation (solar, BESS) that have similar control characteristics.

2. Wind Integration Experience in Other Jurisdictions

This section discusses the experiences of two jurisdictions, i.e. South Australia and Ireland, in integrating large amounts of inverter-based generation into their systems. While every jurisdiction has its own unique characteristics, learnings can be drawn related to technical challenges and how these have been addressed and overcome or mitigated.

2.1. South Australia

South Australia has experienced rapid growth in renewable generation, reaching very high levels of penetration by global standards. These changes have been driven by various government-led renewable energy policies aimed at reducing carbon emissions as well as rapid changes in the economics of power generation, generally favoring renewable generation. During the 2017-18 financial year, renewable generation in South Australia exceeded demand for 366 hours, with the excess energy exported to Victoria via the existing AC and/or DC interconnector.

The South Australian transmission network covers a geographically large area (over 200,000 square kilometers) with approximately 5,600 kilometers of transmission lines, operating at 132 kV and 275 kV. The maximum demand is 3,005 MW. The load and conventional generation are largely concentrated in the Adelaide metropolitan area, however the bulk of the utility scale renewable generation (1,809 MW of wind generation and 135 MW of solar PV generation) is connected to remote parts of the network, with a large cluster of wind generation approximately 200 km north of Adelaide. The utility scale renewable generation is complemented by a significant and rapidly growing amount of rooftop solar PV generation (currently 930 MW of installed capacity). South Australia is interconnected with Victoria via a 275 kV double circuit AC interconnector (650 MW transfer capability) and a voltage source converter HVDC link (200 MW transfer capability). A map of the South Australian transmission system is shown in Figure 2-1.

The nominal frequency of the South Australia power system is 50 Hz.

On 28 September 2016, South Australia suffered a statewide blackout, causing loss of supply to 850,000 customers. While 80% - 90% of load was restored within 8 hours, supply was only restored to all customers by 11 October 2016. The subsequent investigation by the Australian Energy Market Operator (AEMO) found that while extreme weather triggered the sequence of events that led to the blackout, the loss of the AC interconnector that precipitated the complete loss of supply was largely due to the unforeseen sustained reduction in output from a number of wind generators in the state.

Following the blackout and the findings of this investigation, AEMO focused its attention on determining measures to be taken to ensure that the South Australian system continues to operate in a secure state, while accommodating a large and growing amount of renewable generation.

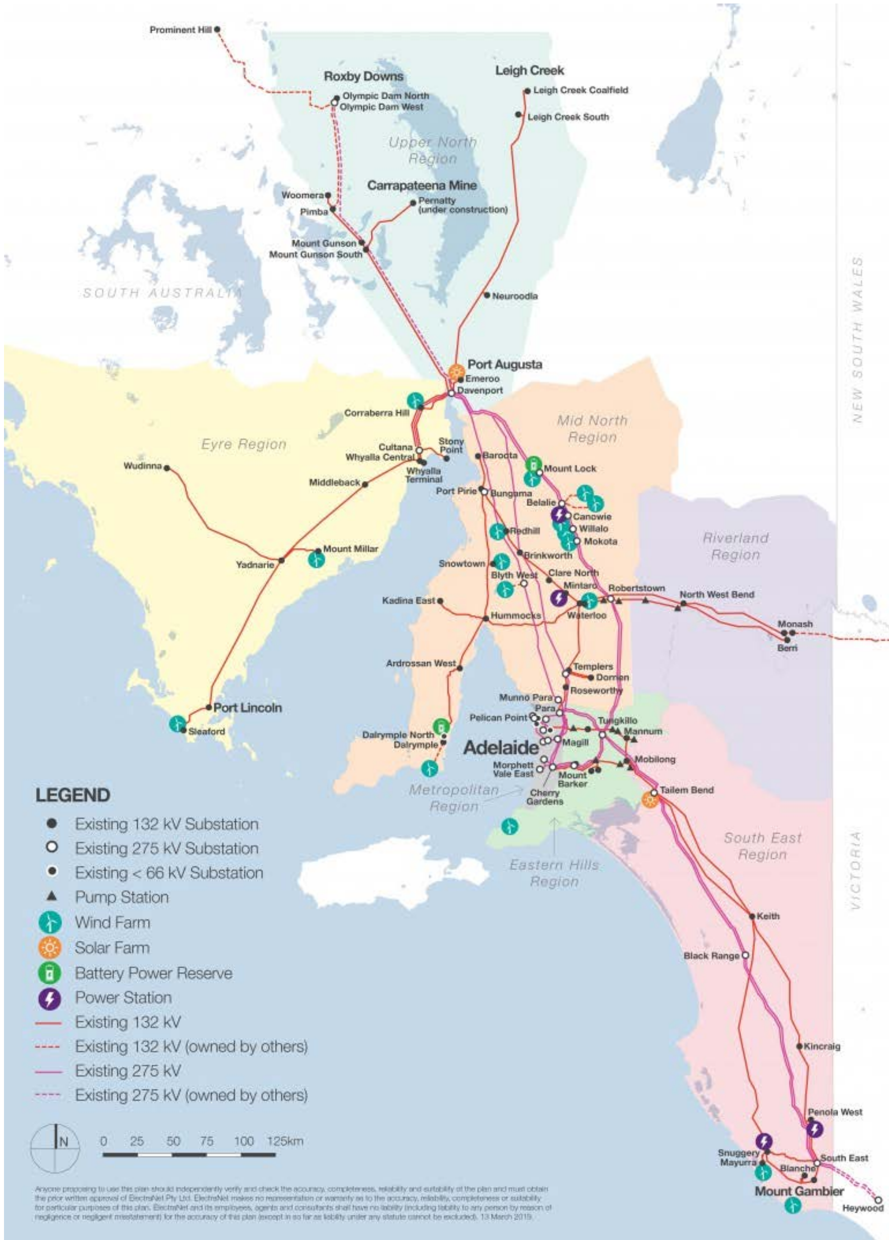


Figure 2-1 South Australian Transmission System Map

In the South Australian context, the following critical issues associated with high renewable penetration have been identified by AEMO:

Low system strength

Low system strength is generally characterized by low fault levels due to high system impedances and low levels of synchronous generation. Given the long transmission distances and sparse, radial network topology, fault levels in the South Australian system are particularly low. This is further exacerbated by the fact that the synchronous generation in service is located relatively far from the major wind generation clusters. Further, as more inverter-based generation is connected in close proximity to other inverter-based systems, the system strength as measured by the short circuit ratio, is eroded even further.

The types of inverters typically used in utility scale renewable facilities require a minimum system strength (often specified as a minimum short circuit ratio) in order to maintain stable operation. This could result in the generator tripping due to contingencies under low system strength conditions that it would otherwise remain connected for. Power electronic devices such as STATCOM are similarly susceptible to low system strength.

Low system strength also results in larger magnitude voltage disturbances, affecting the network in a wider area, than would be the case for a higher strength system.

Low system strength may also cause potential mal-operation of protection systems, with distance protection relays considered particularly susceptible. For example, protection may fail to operate for a fault with possible cascaded tripping due to fault clearance by out-of-zone protection. Protection system adequacy is considered a less critical issue within South Australia as the transmission system protection generally consists of duplicate distance and differential protection, with differential protection able to operate reliably at low system strength.

Frequency control

AEMO manages power system frequency control through the Frequency Control Ancillary Services (FCAS) market. There are eight FCAS markets, consisting of Regulation Raise, Regulation Lower, Fast Raise (within 6 seconds), Fast Lower (within 6 seconds), Slow Raise (within 60 seconds), Slow Lower (within 60 seconds), Delayed Raise (within 5 minutes) and Delayed Lower (within 5 minutes). While the FCAS market is technology neutral, these services have predominantly been provided by synchronous generators. There is some concern that increasing renewable penetration could potentially result in less FCAS capability being available in the market. However, most modern utility scale renewable generators are capable of offering all eight FCAS services with economic tradeoff effects.

Higher penetration of inverter-based renewable generators also reduces the total system inertia. Lower system inertia tends to increase the rate of change of frequency (RoCoF). AEMO found that the reduction in inertia could be mitigated to a certain extent, but not entirely, by increasing the amount of Fast FCAS provided (raise or lower within 6 seconds). In the South Australian context, a certain minimum amount of inertia therefore needs to be online in order to ensure that the rate of change of frequency is limited to less than 3 Hz/s to provide sufficient time for FCAS resources to act and as a last resort, for reliable operation of the UFLS scheme.

AEMO also investigated the possibility of using fast frequency response (FFR) provided by inverter-based systems to compensate for the reduction in inertia. However, it was found that the time delays required for accurate frequency measurement would still make it necessary to have sufficient inertia online. The minimum inertia requirement is simultaneously met when dealing with the system strength issue.

Reactive support shortfalls

The withdrawal of synchronous generation may result in reactive support gaps at key network locations. Northern Power Station, with a capacity of 520 MW was retired in May 2016. This led to a sudden loss of a significant amount of reactive support. ElectraNet is currently considering installing a Synchronous condenser at Davenport (near the network location where Northern Power Station was connected). The synchronous condenser is primarily installed to address the system strength shortfall, however it will also add inertia as well as providing reactive support.

In order to address these issues, the following actions have been taken by AEMO:

1. **Model requirements**
   Inverter-based generation requires a minimum system strength (specified as a minimum short circuit ratio) in order to maintain stable operation. The key component is the phase-locked-loop (PLL), which tracks the phase angle of the grid voltage in order to synchronize the inverter to the grid. As the PLL is either simplified or completely ignored in RMS models, accurate assessment of system performance under very low system strength conditions requires the use of detailed EMT models. Accurate, site-specific and plant-specific RMS models (in PSS®E format) as well EMT models (in PSCAD™ format) must be provided by all generators with capacity above 5 MW seeking to connect to the grid. The PSS®E and PSCAD™ models have to be benchmarked against each other and against site-measured responses obtained during commissioning tests in order to demonstrate that the models accurately represent the plant. Accurate, high fidelity models are of critical importance to AEMO in order to correctly determine the technical envelope of the system, particularly in determining minimum system strength and minimum inertia requirements.

2. **Minimum number of online synchronous machines**
   AEMO developed a detailed PSCAD™ model of the South Australian system, including detailed models of all generators and relevant protection to determine the minimum number of synchronous machines required to be online to provide sufficient system strength at different levels of renewable generation. A complex picture has emerged from this South Australian study, with approximately 65 different combinations of online synchronous machines determined for a range in non-synchronous generation levels. At present, AEMO directs these synchronous generators to run once non-synchronous generation reaches 1,295 MW and a system strength shortfall is predicted.

3. **Renewable FCAS trial and subsequent enforcement**
   Until relatively recently, many inverter-based generators were connected to the network without frequency control capability specified in their performance standard or enabled in the physical plant.

Recognizing that these devices are capable of providing frequency control services, AEMO requested that the ability to provide all 8 FCAS market services be tested at Hornsdale Wind Farm in South Australia to demonstrate the feasibility of these services being offered by inverter-based generation. The trial was a success and AEMO has subsequently insisted that all inverter-based generators seeking to connect to the network incorporate frequency control capability into their technical performance standards and demonstrate their capability to provide these services when commissioning the new generator.

4. Grid code changes

In 2018, a number of changes were introduced to the grid code, specifically imposing more onerous technical performance requirements on generators connecting to the grid. A number of these changes have been made in response to the lessons learnt from the South Australian blackout and with a view to increasing system resilience under low system strength. The key new requirements are:

a. More onerous voltage disturbance withstand requirements
b. Increased RoCoF withstand capability, requiring generators to remain connected for rates of change of frequency of +/-3 Hz/s for 1 second and +/-4 Hz/s for 0.25 seconds.
c. Multiple fault ride through withstand capability, requiring generators to remain connected for up to 15 faults occurring within a 5-minute period.

5. System strength rule change

In 2018, following the introduction of the “Managing power system fault levels” rule change, new measures were introduced to address system strength issues within the Australian interconnected system. This rule change had two key components:

a. AEMO determined minimum fault levels at a number of designated fault level nodes, effectively introducing a lower limit to system fault levels that should not be breached in order to maintain reliable system operation. In South Australia, the fault level nodes and associated minimum fault levels were: Davenport 275 kV bus - 1,150 MVA, Robertstown 275 kV bus - 1,400 MVA and Para 275 kV bus – 2,200 MVA). AEMO found that a system strength shortfall currently exists in South Australia. ElectraNet, the transmission system owner and system planner in South Australia has proposed mitigating this system strength shortfall by installing a number of synchronous condensers by 2020. ElectraNet further proposed specifying these synchronous condensers to have higher inertias (by fitting flywheels to the synchronous condensers) to assist in limiting the rate of change of frequency in South Australia. This has been proposed on the basis that the additional capital cost is relatively low, while the benefits are significant.
b. All new generator connections are assessed at an early stage of the connection evaluation process to establish whether they would have an adverse impact on system strength to mitigate adverse system strength impacts. The network service provider performs a preliminary system

strength impact assessment (PIA) using steady state analysis tools and if necessary, a full impact assessment (FIA) using electromagnetic transient (EMT) models at the connection inquiry stage. Should this assessment indicate an adverse system strength impact, then approval of the connection application would be subject to the generator agreeing to take action to restore system strength to acceptable levels. This requirement has resulted in synchronous condensers being required for a number of inverter-based renewable projects. Renewable generators are particularly likely to be affected as they tend to connect to relatively weak grid locations and reduce system strength by reducing the effective short circuit ratio. This rule change has unfortunately had some potentially negative consequences, with generators attempting to use system strength to disadvantage competitors and inefficient network investment due to synchronous condensers being installed on a per-project basis instead of optimizing system wide benefits.

6. **Minimum inertia requirement**

   AEMO performed detailed studies to determine the minimum inertia requirements for each state in the interconnected system. In the South Australian context, the minimum inertia requirements are easily met when the minimum number of synchronous machines are online to ensure that the system strength requirements are met. For this reason, system strength is more critical than frequency control at this point in time. Given that ElectraNet are proposing installing synchronous condensers with higher inertias to mitigate the system strength issue, the minimum inertia requirement is likely to be met without significant market intervention as is currently the case, with AEMO directing certain synchronous generators to run during periods of high wind generation.

In addition to these measures, final approval from the Australia Energy Regulator (AER) is currently being sought for the construction of a second AC interconnector, a 330 kV double circuit line from the mid north region of South Australia (where a large amount of wind generation is currently connected) to Wagga in the neighboring state of New South Wales (also a region where large amounts of wind and solar PV generation is connected). The second AC connector will be designed to provide a nominal transfer capacity of 800 MW. The benefits of this interconnector are increased system security in South Australia, considered essential given the increasingly credible loss of both circuits of the existing AC interconnector, as well as facilitating increased penetration of renewables.

South Australian System Characteristics relevant to renewable penetration:

- **Total installed wind capacity**: 1,809 MW (29.2% of total installed generating capacity, including rooftop PV))
- **Total installed solar capacity**: 135 MW utility scale (2.2% of total installed generating capacity, including rooftop PV) and 930 MW rooftop PV (15% of total installed capacity)

- **Total installed synchronous condenser**: None at present, however ElectraNet plans to install synchronous condensers by 2020 to address the system strength and inertia shortfall. This shortfall is currently managed by AEMO directing synchronous machines to run, however ElectraNet's analysis indicates a net market benefit for synchronous condensers to be used instead.
- **Total installed battery**: 130 MW, consisting of Hornsdale: 100 MW / 129 MWh and Dalrymple: 30 MW / 8 MWh.
- **Minimum required total online inertia**: At present, the minimum online inertia required is 6,000 MW.s. This figure is based on SA operating as an island, taking into account the potential loss of the largest synchronous generator in the state, the Pelican Point gas turbine, which withdraws 1620 MW.s of inertia. The minimum threshold inertia after losing the Pelican Point gas turbine is 4,400 MW.s
- **AC or DC ties to other systems: AC interconnector**: a double circuit 275 kV line to Victoria with bi-directional transfer capacity of 650 MW. DC interconnector: a DC link with Victoria with transfer capacity of 200 MW (import to SA) and 220 MW (export from SA). The transfer capacity of the DC link is often limited by constraints within the Victorian system.
- **Largest single contingency in the system**: Loss of the largest generating unit, the 750 MW generator at Kogan Creek in Queensland for the interconnected system or the loss of the largest generator in SA if islanded. This is the 160 MW Pelican Point gas turbine (which has high inertia) or to a lesser extent the loss of a Torrens Island Power Station as turbine (200 MW), depending on unit commitment. The loss of both circuits of the double circuit AC interconnector (up to 650 MW) may be reclassified by AEMO as a credible contingency should there be an increased risk to extreme weather or bushfires.
- **What is the highest recorded inverter-based generation in the system**: Renewable penetration can be measured in a number of different ways. Table 2-1 lists renewable penetration in 2017-18 by installed capacity, energy consumption and as a percentage of state-based demand. At periods of 100% penetration, the minimum number of synchronous machines remain online as described above and South Australia is exporting to Victoria.
- **Peak summer load**: SA Summer 2018 operational maximum demand was 3,005 MW, occurring at 7:30 pm. The time at which maximum demand occurs has in recent years shifted later in the evening by increasing rooftop PV penetration.
- **Peak winter load**: Winter peak operational demand is approximately 2400 MW.
- **Minimum load**: A major consideration is the minimum demand, presently about 646 MW (2017-18 actual, recorded at 1:30 pm), occurring in the early afternoon due to high rooftop PV generation (approximately 930 MW installed capacity in 2017-18, with approximately 820 MW output at minimum demand). The minimum demand is forecast to become negative by 2024 (90% POE) and continue to fall thereafter.

Table 2-1: Renewable Generation in 2017-18 by Installed Capacity, South Australia

Description	Wind value for South Australia	Rooftop PV value for South Australia
Capacity penetration: installed capacity as a percentage of total installed generation*	40%	16%
Energy penetration: ratio of annual energy to annual total energy consumption**	43%	9%
Maximum instantaneous penetration (excluding exports): maximum observed ratio of energy to demand at any instant in time during the year**	138%	33%
Periods of 100% (or greater) instantaneous penetration	366 hours	0 hours

* Wind calculations are based on AEMO registered capacity for all South Australian generating systems at the end of the financial year. However, excluded are generating units that are effectively mothballed for more than six months of the financial year, and wind farms whose output did not yet reach 90% of registered capacity by end of the financial year. Rooftop PV capacity penetration is calculated by adding estimated rooftop PV capacity at end of the financial year to registered capacity.

** Wind generation analysis is based on operational demand as generated, whilst rooftop PV is based on underlying demand.

- **Lowest frequency dip experienced in the system**: 47 Hz, just prior to frequency collapsing completely during the SA system blackout event on 28 September 2016.
- **Load shedding considered for low frequency events?** Yes. However, UFLS is considered an operational measure and is not taken into account when planning the system.
- **Rate-of-Change-of-Frequency (RoCoF) relays in the system**: Yes, on generators. RoCoF in the system must be limited to 3 Hz/s for the UFLS scheme to operate reliably.

2.2. Ireland

The Irish transmission system comprises two distinct areas; the transmission system of Ireland (IE) operated by EirGrid at 400 kV, 220 kV and 110 kV and the transmission system of Northern Ireland (NI) operated by SONI at 275 and 110 kV. The two systems are electrically connected by means of one 275 kV double circuit from Louth in IE to Tandragee in NI. There are also two 110kV connections: Letterkenny in IE to Strabane in NI and Corraclassy in IE to Enniskillen in NI. The 400 kV, 275 kV and 220 kV networks form the backbone of the transmission system and the whole system is operated as an All-Island system. System peak is experienced in winter months due to greater heating and lighting requirements and peak is around 6500 MW. The minimum demand on the system is in summer months, termed “minimum summer night valley” and is around 2500 MW. The Irish transmission system map is shown in Figure 2-2.

The nominal frequency of the Irish power system in 50 Hz.

As part of European Union’s binding national targets, Ireland is committed to 16% of the country’s total energy consumption to come from renewable energy sources by 2020. The total energy consumption includes heating, transport and electricity. In the electricity sector this target necessitates a significant increase in the amount of renewable generation on the Irish power system and an All-Island Grid study (published in 2008) concluded that up to 42% of renewable generation could be accommodated on the whole Irish system (Ireland and Northern Ireland). In 2010, EirGrid and SONI published the study results on the Facilitation of Renewables (FoR) [5] summarizing the operational implication of managing such high levels of variable renewable generation on the system. In 2011, EirGrid in Ireland and SONI in Northern Ireland embarked upon a multi-year project referred to as DS3 (**D**elivering a **S**ecure, **S**ustainable electricity **S**ystem) to meet the 40% renewable electricity target by 2020. This is expected/planned to be delivered largely by wind (around 37%) and is the highest for any synchronous system in Europe.

As part of the FoR studies, a number of possible system issues has been identified and these have been categorized according to severity as those that impose fundamental operational limits, those that may impose fundamental operational limits, those that impose operational limits but can be mitigated and those that seem not to impose operational limits. Among those the most important technical issue encountered is frequency stability and its emergence cannot be mitigated via current technology. An overview of the issues identified is given in Figure 2-3.

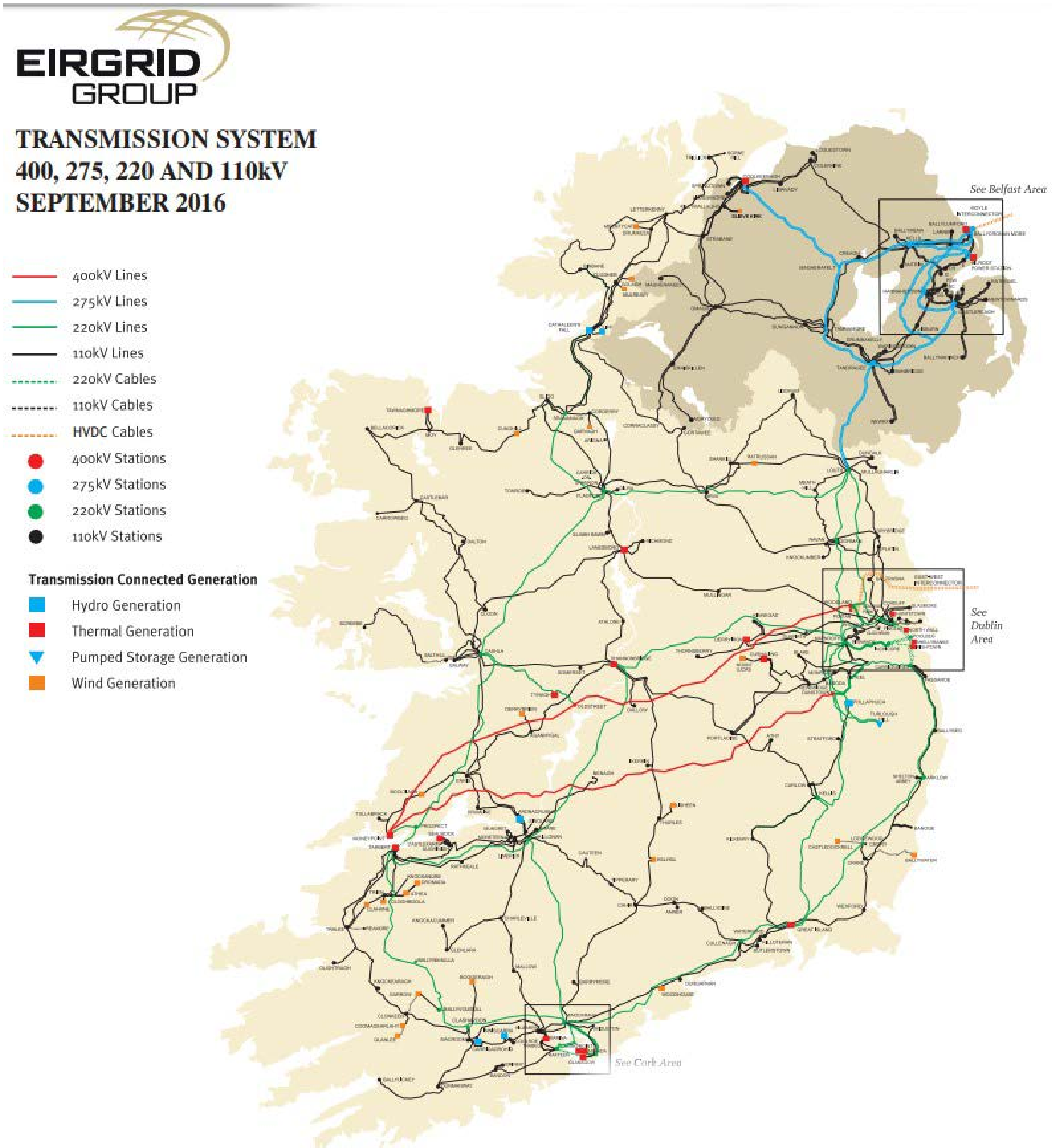


Figure 2-2 Irish Transmission System Map

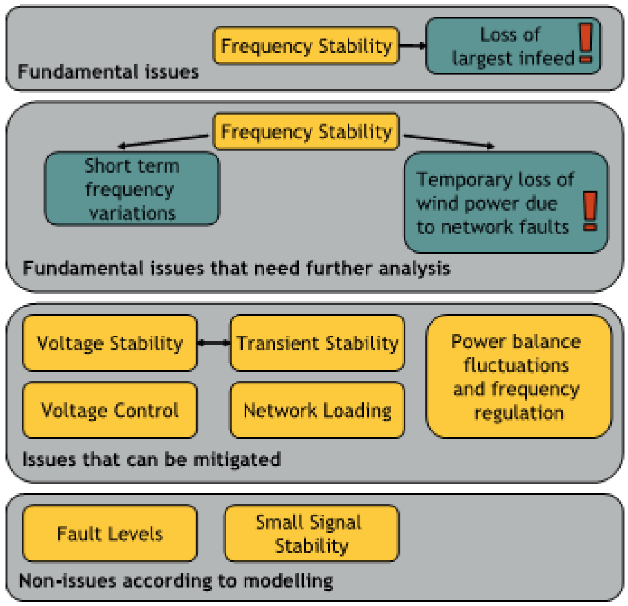


Figure 2-3: Classification of Issues in the Irish Power Grid

As part of the studies, a metric that captures range of issues with a single constraint was developed termed as System Non-Synchronous Penetration (SNSP). This provides a measure of the non-synchronous generation on the system instantaneously and is defined as the ratio of the real-time MW contribution from non-synchronous generation and the net HVDC imports to demand plus net HVDC exports. Increasing this operational metric, results in a decrease in system inertia as more and more conventional power plants are replaced with inverter-based generation. The exact change will depend on the dispatch scenarios and the individual inertia constants of each dispatch unit, however in general the level will decrease. Therefore, a second operational metric that considers instantaneous system inertia is considered. This is a ratio based on the stored kinetic energy in conventional generator plants and loads to the dispatched power of the largest infeed (MW.s/MW) considering that the generators and loads (rotating) will have a strong impact on the frequency response to system disturbance such as the loss of generation. Further operational metrics have been considered, the most prominent one being the minimum number of conventional units being online. This was checked against a minimum level of 100 MW units with no clear correlation between online units and the SNSP operational metric. Decreasing the minimum level of generators considered to 50 MW has not revealed any correlation and hence the metric is not considered to provide a global picture.

Wider study results suggested that keeping frequency within the acceptable boundaries following loss of largest infeed with some operational maneuvering (such as de-sensitizing RoCoF relays and implementing restriction on imports) is possible and that operational levels of 70 to 80% on the SNSP metric and 20 to 30 MW.s/MW on the second metric can be reached. Similar frequency stability studies following system faults suggested an operational limit of 60 to 70% on the SNSP metric and 20 to 30 MW.s/MW.

On the voltage stability and control side, analysis indicated that there will be increased demand for reactive power support and that these can be mitigated by reinforcing the grid code compliance requirements of wind generation on provision of reactive power capability, installation of reactive power sources such as static var compensators at strategic locations and identification and definition of conventional “must run units”. On the interrelated transient stability side, study results identified that beyond 70 to 80% SNSP, is likely to experience issues.

On power balance regulation, ramping up and down of conventional generation was investigated and result indicated that introducing some form of curtailment in extreme positive ramp situation would help reduce power gradients. The study also concluded that reinforcing the 110kV network especially at remote areas for loading purposes would greatly facilitate the implementation of the 2020 scenario.

Small signal stability identified as a non-issue as the increased wind generation improved the damping of oscillation in the system. Few inter-area and local modes were identified as less damped, but these did not pose a threat to the stability of the system. On fault level side, the study checked whether the lowest fault level during increased wind generation will be equal or higher than the minimum fault level experienced with no wind power in the system. The analysis concluded this not to be an issue.

Following identification of technical issues and constraints, the project moved onto developing the required technical and commercial mechanism to facilitate, incentivize and hence improve system performance and capability. The DS3 project included multiple workstreams all neatly combined under three categories: system performance, system policies and system tools. Each of these areas were deemed as fundamental to the success of delivering 40% renewable electricity target and hence each were set with their own objectives. In system performance objectives were concentrated on providing current and future plant performance capability, enhancing existing monitoring processes with grid code compliance, ensuring the development of a portfolio of plant aligned with the long term needs of the system and review of RoCoF requirements. Adapting and updating system operational policies to align with managing the voltage and frequency securely on an All-Island basis was set as part of the system policy objectives along with availability of renewable generation data for analytical purposes. And lastly, objectives were set to develop and implement enhanced tools to manage increased system complexity and provide support in decision making in the control centers.

A comprehensive review of System Services [6] was carried out in order to identify the needs, effectiveness of the existing services at the time and payment structures and more importantly develop new services with new and/or revised payment structures that foster focus on performance and investment. As a result of the review by the Single Electricity Market (SEM) Committee, 14 System Services aiming to support frequency and voltage control were designed to be provided by the existing and new entrants (such as battery storage). The identified and implemented services are:

- Synchronous Inertial Response (SIR)

- Fast Frequency Response (FFR)
- Dynamic Reactive Response (DRR)
- Ramping Margin 1 Hour (RM1)
- Ramping Margin 3 Hour (RM3)
- Ramping Margin 8 Hour (RM8)
- Fast Post-Fault Active Power Recovery (FPFAPR)
- Steady-state reactive power (SRP)
- Primary Operating Reserve (POR)
- Secondary Operating Reserve (SOR)
- Tertiary Operating Reserve 1 (TOR1)
- Tertiary Operating Reserve 2 (TOR2)
- Replacement Reserve (De-Synchronised) (RRD)
- Replacement Reserve (Synchronised) (RRS)

Out of the 14 services, SIR, FFR, DRR, RM1, RM3, RM8 and FPFAPR were new services. Procurement of these services were done on an interim basis until 2018 and since then moved to a regulated contract tariff. As a result of this initiative, 11 conventional units have revised their technical offer data improving load up rates, synchronization notice time etc., 8 conventional (synchronous) units have reduced minimum load for provision of SIR with a net benefit of 330 MW and 12 conventional units are providing FFR (around 210 MW) all indicating a positive operational impact. In addition, a number of wind units are contracted to provide a number of services such as POR, SOR, TOR1, FFR and SSRP as well emulated (synthetic) inertia. Similar impact has been observed on demand side also with 20+ units providing various services.

To date the highest wind generation occurred last December (2018-12-12) with a peak of 3939 MW. At the time of this generation the load was recorded as 5588 MW equating to 70.5% of demand being supplied by wind. This should not be confused with the operational metric SNSP for which the latest winter peak period figure was around 62.8%. Higher SNSP numbers on the system have been reached especially during periods of lower demand and currently there is an operational limit of 65% SNSP. There are plans to increase the level of SNSP from the current limits of 65% to 70% initially and then to 75% within the next year if Ireland is to meet the 40% target. Currently, the biggest issue with the increase of SNSP is due to RoCoF relay settings. The requirement is to increase the settings to 1Hz/s making sure that the generation portfolio can meet this (or that the volume of non-compliance is manageable). The second hurdle is the introduction of decision-making support tools in control center environment.

The following bullet pointed list contains few background information about the Irish system for the reader to have a feel and draw their own conclusions in terms of comparison with other systems.

- Total installed wind capacity: All Island about 5 GW, approximately 3.7 GW in Ireland and 1.3 GW in Northern Ireland.

- Total installed solar capacity: Approximately 100 MW in Northern Ireland and none in Ireland.
- Total installed synchronous condenser: None dedicated, one of the units in Northern Ireland can be operated as synchronous condenser.
- Total installed battery: Only one battery in Northern Ireland – Kilroot 10MW. A lot of batteries are being installed as a result of the new DS3 system services. As service procurement is in the execution stage, information is very scarce.
- Minimum required total online inertia: Currently there is a floor of 23,000 MW.s on an All Island basis. They have plans to drop it to 20,000 MW.s and then subsequently to 17,500MW.s before the end of 2020. This change is linked to increased SNSP and RoCoF changes.
- AC or DC ties to other systems: Two DC ties Moyle 500MW LCC to Scotland and EWIC 500 MW VSC to England considering that the system is operated as an All-Island system. Between Ireland (EirGrid) and Northern Ireland (SONI) there is one 275kV double-circuit line and two 110kV single-circuits.
- Largest single contingency in the system: Changes depending on the interconnector flows and the generation dispatch. In general, it is either the trip of one HVDC interconnector or the trip of a large synchronous unit. Normally during the load peak, the LSI is between 400 MW and 500 MW.
- Amount of reserve provided through the tie lines: The HVDC's can give up to 75 MW each as static reserve.
- Highest recorded inverter-based generation in the system: The highest wind generation was recorded in December 2018 with a peak of 3939 MW when the load was 5588 MW at the time, so the wind supplied 70.5% of the demand.
- Peak summer load: About 2.5 GW on an All-Island basis.
- Peak winter load: About 6.5 GW on an All-Island basis.
- Lowest frequency dip experienced in the system: 49.249 Hz from 2017 published results.
- Load shedding for low frequency events: Yes, they have interruptible loads as part of an ancillary service referred to as Demand Side Units (DSU), which are contracted to provide static POR (primary operational reserve) and it triggers at 49.8 Hz. Under-Frequency Load Shedding is the very last resort to secure the system in case of a severe frequency event – it operates in stages starting at 48.85 Hz.
- Rate-of-Change-of-Frequency (RoCoF) relays in the system: Transmission level is set at 0.5 Hz/s and is being increased to 1 Hz/s. At distribution level it is used as Loss of Mains protection.

3. Study Methodology

This section describes the general methodology followed in this study to determine acceptable levels of wind generation that can be integrated for existing and future system conditions without introducing major system technical challanges. For this particular study, the technical performance criterion for acceptability is the transient stability of the system. Furthermore, fault level recovery criteria were also checked and these are described later in this section.

Therefore the core of the analysis is transient stability simulations which were performed in PSS®E version 33. At a high level, the study mainly looks into the system response a few seconds after a system disturbance.

Transient stability simulation is a well-established method used to study the rotor angle stability in power systems. The differential and algebraic equations describing the system are solved successively at discrete time steps in RMS time domain (effectively an electromechanical time domain study). The typical time step used to advance the state of the system is quarter of a cycle. The power electronic devices such as HVDC controls or inverter-based generation controls are represented by their average behavior.

The simplifications that are applied to component models in transient stability simulation allow the response of very large interconnected systems within a time window of 10 to 20 seconds to be investigated. On the other hand, the simplified models might mask some potential issues. This is the case, for example, for phase-locked loop components used to synchronize inverter-based generation to the grid. The phase-locked loop relies on the measurement of voltage at the point of interconnection to provide a reference for synchronization. In weak systems, characterized by low short circuit ratios, this measurement is challenged, potentially causing instability. To capture this behavior, a finer time domain study (in electromagnetic study time scales) is required.

The initial starting point of the study was to look into the existing system. After assessing the current situation, the analysis was continued by adding a second 345-kV tie to New Brunswick. This is a major system reinforcement measure which eliminates islanding of Nova Scotia in the event of tripping the exising 345-kV tie (assuming N-1 criteria, and limiting transfers with transmission planned or unplanned outages). The main reason to repeat the studies with this system development is that it is expectated that this measure will allow the wind levels to be increased beyond the exising level if other criteria are also met[3].

The study next looked into how much wind can be added without a second tie but rather with increasing the effective online inertia on the Nova Scotia system in islanded operation by utilizing fast-acting energy storage technology and voltage regulators.

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[3] It should be recognized that other islanded scenarios which are not included in this study, such as the Maritimes Area islanded from New England, Cape Breton islanded from mainland Nova Scotia, must be properly analyzed before any findings could be operationalized.

Although the use of a more comprehensive (and hence more costly) hybrid solution consisting of both a second tie system reinforcement measure and the introduction of synchronous condenser and/or battery storage can be considered, this option has been left out of the analysis for the time being due to increased complexity and likely costs.

Renewable generation is intermittent in nature and hence in the case of wind generation, sufficient regulation reserve is needed to accommodate wind fluctuations in longer time frames. Using recorded data from the Nova Scotia SCADA system and through a simplified analysis introduced in Section 3.2, *Estimation of Regulation Reserve*, thresholds are established for regulation reserve in order to be able to accommodate wind fluctuations. The purpose of this part is to evaluate, before stepping into transient stability simulations, whether there is enough regulation reserve in the system to accommodate fluctuations in time frames of tens of minutes which are known to cause system stability issues.

The base cases used for transient stability simulation will have generation dispatched to meet the following requirements:

- MW output is set so that tie line flows match the case summary.
- Contingency spinning reserve is not dispatched, as it is assumed that under-frequency load shedding is used to handle the frequency fall from a tie line trip. (Note that Tasmania relies on load shedding for a HVDC tie trip, however this is a direct inter-trip and not based on frequency measurement).
- Regulation reserve is dispatched to handle fluctuations in wind generation and demand and keep the AC tie flow constant. The Maritime Link HVDC tie can be used to provide ± 60 MW of regulation reserve using its frequency dependent power modulation. If this is insufficient then regulation reserve can be provided by battery storage or by conventional generators. (Battery storage is already used in other jurisdictions to smooth the output from windfarms, for example the 315 MW Hornsdale windfarm in South Australia has an adjacent 100 MW 129 MWh battery).

3.1. Overview of Transient Stability Simulation

Figure 3-1 shows in a flowchart style how the study is performed. Note however that:

- For the existing wind analysis, mitigation only consists of existing system manipulation such as bringing more thermal units online or switching shunts on or off. These changes will be applied to the original base cases and will be kept in the models for the simulations to follow.
- For the second tie analysis, the main mitigation measure is effectively added prior to adding more wind.

- For analysis without a second tie and with synchronous condenser and battery options, wind is increased in steps of 100 MW. The final stop point is somewhat subjective and dependent on the results observed in the previous steps.

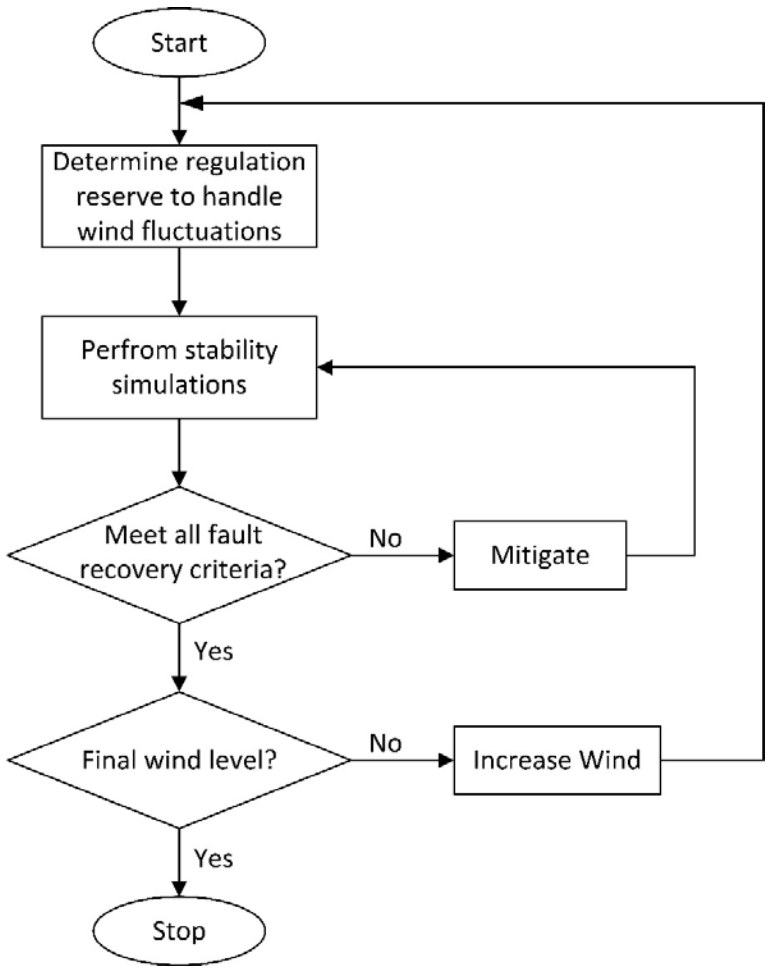


Figure 3-1: General Flow of Simulation

The criteria checked for each simulation are:

- No cascade generator or transmission line tripping
- No loss of synchronism
- Frequency maintained with the frequency fault ride-through envelope
- Voltage at generator connection points maintained within the voltage fault ride-through envelope
- No thermal overloads on lines
- Fault current levels sufficient to operate transmission and distribution protection

- Short Circuit Ratio with Interaction Factors (SCRIF) maintained for wind generation (to ensure that the PSS®E model is valid). The SCRIFs will be calculated with the additional new wind farms.

As a measure for validity of transient stability simulations, and as an additional check, short circuit ratios at nodes with wind generation are calculated. The methodology used for this calculation is explained in Section 3.3, *Calculation of Short Circuit Ratio*.

3.2. Estimation of Regulation Reserve

In any given electric power system there is a need to balance generation and demand so that a stable operating equilibrium with constant frequency can be maintained. Reference to system frequency is due to the fact that it is representative of the rotational speed of the synchronized generators connected and also that it is a shared parameter by all participants within the power system. Disturbance in the balance between generation and demand causes a deviation in the frequency and needs to be offset quickly. As there is limited ability to store kinetic energy, the energy is usually stored in other forms (water in reservoir for example). System operators keep a finite amount of generating capacity as reserve (usually termed as operating reserve) in order to meet demand in case a generator is no longer capable of generating or there is another level of disturbance to the generation. In most electric systems the level of the reserve is at least equal to the amount of the largest generator plus a finite amount of peak load. There are other types of reserve such as frequency-response reserve and replacement reserve but the explanation of these are beyond the scope of this report. Inclusion of renewable generation introduces a form of intermittent power where some of this power maybe lost due to lack of original energy source(s). Therefore, an increased amount of reserve, here termed regulating reserve may be required to cover the intermittency and associated shortages of power. Before any studies can be conducted the level of regulating reserve was calculated to check whether this will have a major impact on the level of renewable generation integration. The methodology of how this level was established is described next.

The simplified methodology used to estimate the regulation reserves required to handle wind fluctuation is described below:

1) From the 5-min controllable infeed (Conventional Generation + Tie Import), at the beginning of every half hour, interpolate the straight-line controllable infeed for every 5 minutes within the half hour. This is assumed to be the system operator's forecastable 5-min controllable dispatch used for controllable ramping. Note that the controllable infeed equals the Uncontrollable Demand + Losses – Wind Generation[4].
2) For every 5-min value, find the deviation between the 5-min controllable infeed and the straight line controllable infeed. This deviation is assumed to be provided by regulation reserve.

[4] For 137MW of unmetered COMFIT wind sites, the 5-min generation values were estimated based on a ratio of actual wind data.

3) Plot a bar graph of positive and negative deviations in 5-MW bins.
4) Find the 3-sigma value for positive and negative deviations. This gives the required positive and negative regulation reserve from controllable sources.
5) Observe whether the 3-sigma values change as more wind generation comes online.
6) Develop a simple equation relating wind generation to regulation.

The linear relationships between the installed capacity of wind and the regulation reserves calculated based on the above methodology are shown in Figure 3-2 and Figure 3-3 along with the developed equations for positive and negative regulation respectively. The summarized results of the regulation reserve calculated using this methodology is shown in Table 3-1.

Table 3-1: Regulation Reserve

Year	Installed Capacity (MW)	Non telemetered Capacity (Year End) (MW)	Telemetered Capacity (MW)	Estimated Telemetered (Ratio Method) (MW)	Regulation Reserve - Installed Capacity (MW)	Regulation Reserve (3-Sigma)	
						Negative [MW]	Positive [MW]
2015	549	96	453	0.0	453.0	-26.3	25.4
2016	580	110	470	0.0	470.0	-28.3	27.3
2017	595	122	473	122.0	595.0	-32.3	30.4
2018	595	113	482	113.0	595.0	-30.8	29.5
Projected values based on linear approximation					700.0	-35.2	33.1
					800.0	-38.5	35.9
					900.0	-41.8	38.7
					1000.0	-45.1	41.5

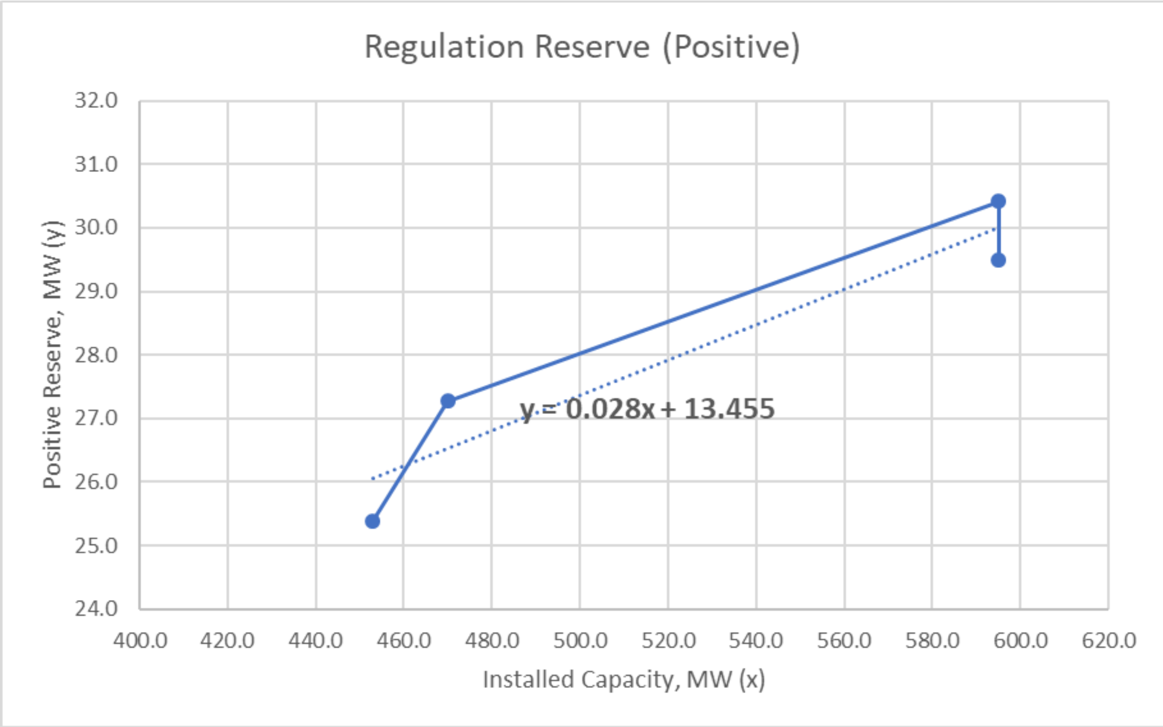


Figure 3-2: Linear Approximation for Positive Regulation Reserve Estimation

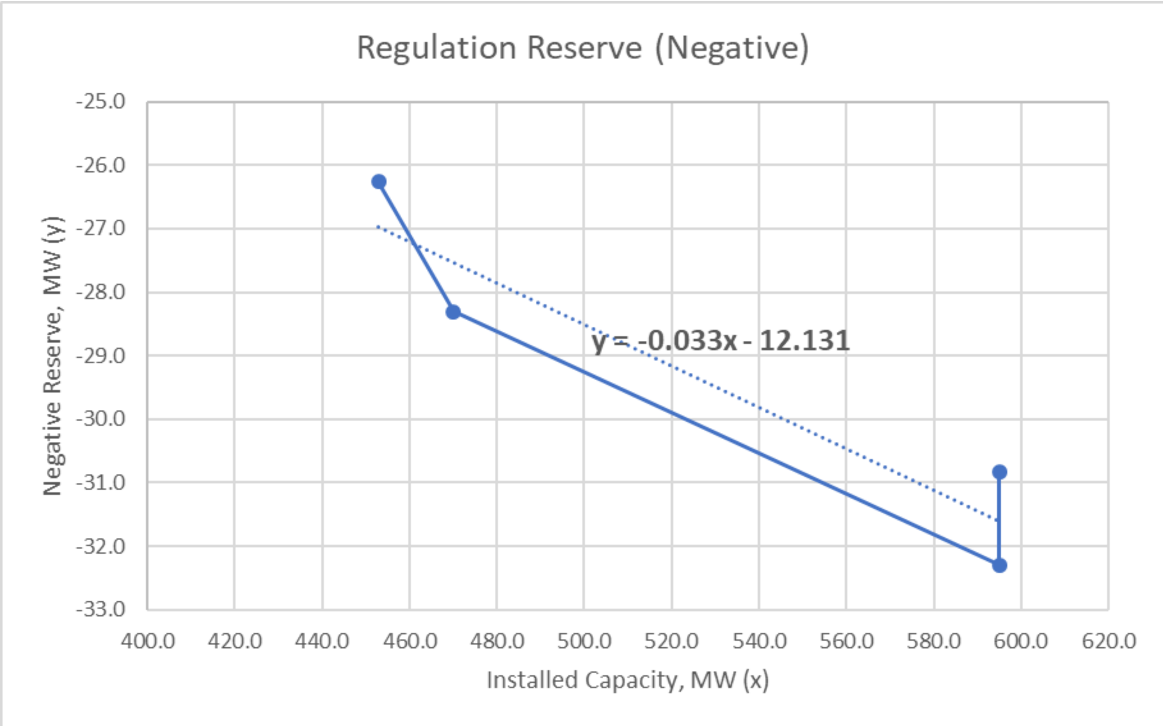


Figure 3-3: Linear Approximation for Negative Regulation Reserve Estimation

3.3. Calculation of Short Circuit Ratio

Grid strength in many jurisdictions is one of the challenges of connecting inverter-based renewable resources to the integrated Bulk Electric System (BES). Strong grids can provide stable reference source for the renewable resources at the point of interconnection (POI). Short Circuit Ratio (SCR) is commonly used to measure the relative grid strength. The short circuit ratio at the POI is defined as follows [3].

$$SCR_{POI} = \frac{SCMVA_{POI}}{MW_{POI}}$$

Where

$SCMVA_{POI}$ = Short circuit MVA level at POI (without wind generator)

MW_{POI} = Nominal power rating of the inverter-based wind generator being connected at POI

In case of multiple inverter-based generators connected in an electrically close region, SCR calculated using the above formula cannot be applied to represent grid strength accurately. Short Circuit Ratio with Interaction Factor (SCRIF) is the more rigorous method that considers the impact of all other generators in the vicinity of POI considering electrical closeness. *SCRIF* at POI of wind generator i is defined as:

$$SCRIF_i = \frac{S_i}{P_i + \sum_j (IF_{ji} \times P_j)}$$

Where

S_i = Short circuit MVA level at POI of wind generator i

P_i = Nominal power rating (MW) of wind generator i being connected at POI

P_j = Nominal power rating (MW) of wind generator j

IF_{ji} = $\Delta V_i / \Delta V_j$ (change in bus i voltage for a change in bus j voltage)

For Nova Scotia system, the SCRIF was calculated for different cases to evaluate the grid strength at point of interconnection of wind generators.

There is no universally accepted level of SCR or SCRIF value that is deemed to be safe for modelling and/or operational purposes. However there is a generally accepted view that a value of 3 or higher provides a somehow acceptable level. With this in mind and based on wind turbine manufacturer advice [7], the SCR threshold is set to 3 for PSS®E Vestas Wind Turbine Generator (WTG) model. It is mentioned that at very low SCR values, EMT models (i.e. PSCAD™) provide a more accurate representation of the interaction of the power plant equipment, which in turn results in improved accuracy of the studies. Since, there is no absolute defined minimum SCR, the above is used to provide direction for further validation of the results. It must be noted that at some wind farm locations in the Nova Scotia system, the short circuit level is low providing SCRIF values below 3.

4. System Description and Modeling

This section aims at providing a better understanding of the conditions under which the system has been analyzed, models used in the analysis and the contingencies applied.

4.1. Overview of Nova Scotia Electrical System

Figure 4-1 shows Nova Scotia's simplified bulk power system. It is connected to New Brunswick through one 345-kV (L-8001) and two 138-kV (L-6535, L-6536) AC transmission lines, which join to a single circuit at Springhill (effectively the interconnection is a single 345-kV line in parallel with a single 138-kV line). It is also connected to Newfoundland through Maritime Link which is a Voltage Source Converter (VSC) HVDC transmission with two poles.

There are fifteen major transmission substations in Nova Scotia, and the transmission voltages consist of 345 kV, 230 kV, 138 kV, and 69 kV. Major thermal generating plants are Lingan, Tufts Cove, Trenton, Point Aconi, and Point Tupper. Transmission-connected wind generation facilities are spread throughout the province. In addition, there are distribution connected wind generating facilities, some of which are not metered. The total installed wind capacity is approximately 600 MW.

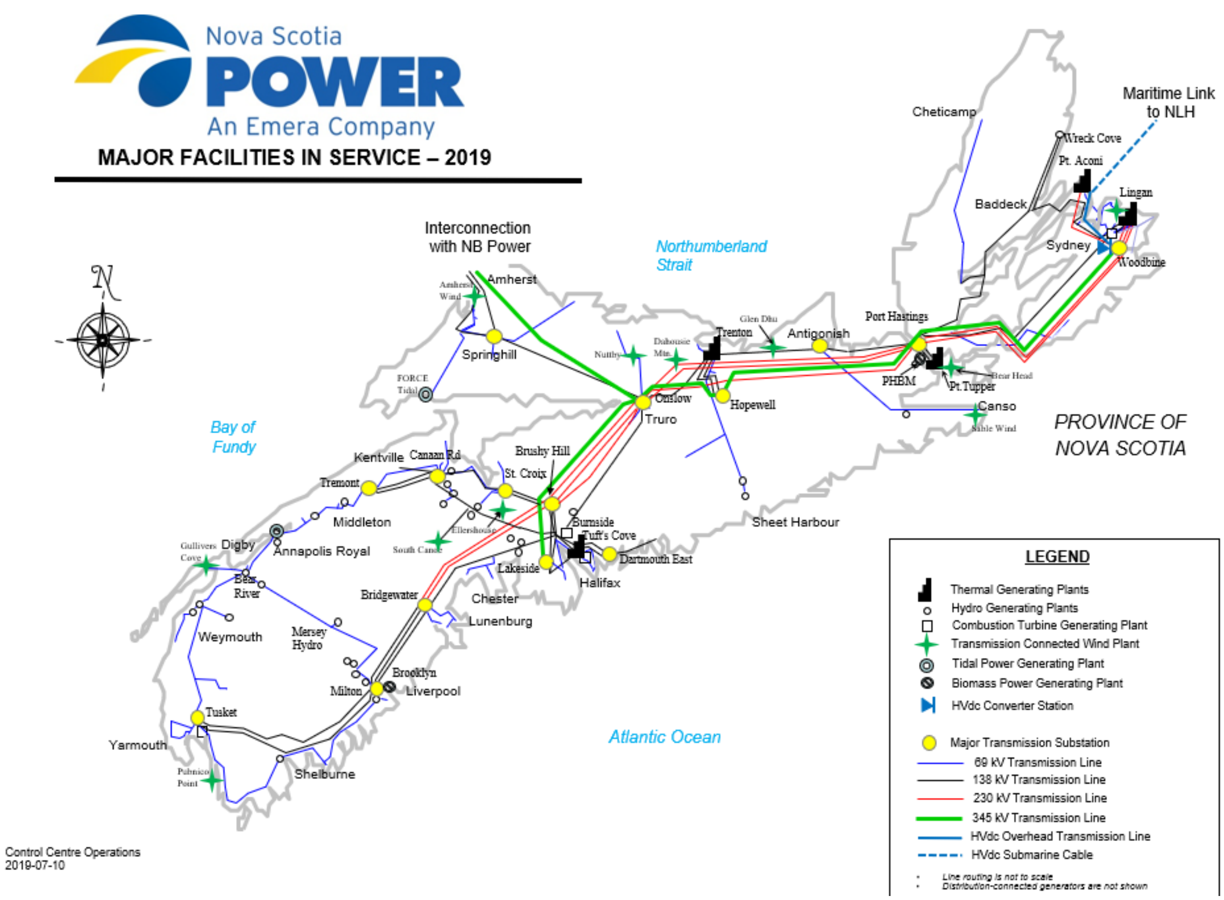


Figure 4-1: NSPI Major Facilities Map

4.2. Power Flow Models

The overall studies are based on a very limited number of cases. These cases have been provided by Nova Scotia Power and are believed to represent indicative system conditions where system issues may be encountered. The four base cases provided for this study are listed in Table 4-1 and some further explanation per case follows the table.

Table 4-1: Summary of Original Base Cases

Base Cases	Case 01	Case 02	Case 03	Case 04
NS* Basic Load [MW]	678	1214	1675	1604
NS Total Generation [MW]	670	793	1815	787
NS Conventional Generation [MW]	85	208	1230	202
NS Wind Generation [MW]	585	585	585	585
NS Thermal Units Online	0	2	8	1
NS to NB† (+: export) [MW]	-250	0	500	-410
NS to NL‡ (+: export) [MW]	200	-475	-475	-475
Nova Scotia Online Inertia [MW.s]	387	1788	6666	1347
Total Online Inertia [MW.s] Pre-contingency	501853	1788	505558	506711

* NS: Nova Scotia
† NB: New Brunswick
‡ NL: Newfoundland

Case 01 is a light load case with high import from New Brunswick. There are no thermal units online. Under this case Nova Scotia will experience under-frequency if islanded from New Brunswick with the loss of the tie.

In Case 02 Nova Scotia is already islanded from New Brunswick. Two thermal units are online for frequency (wind/load) regulation and there is high import from Newfoundland. The contingencies within the Nova Scotia system have pronounced impact on voltage and frequency.

Case 03 is a shoulder load case with high internal Nova Scotia flows. For the purposes of this case, new wind would replace Cape Breton generation. Nova Scotia delivers reserve to New Brunswick in addition to flow-through service from Newfoundland to New Brunswick. If the 345-kV intertie from NS to NB is lost, a Special Protection System will run-back import from Newfoundland to prevent Nova Scotia from islanding.

Case 04 is the high summer peak load case with one thermal unit online. New Brunswick delivers reserve to Nova Scotia with high import from Newfoundland.

Note that these base cases were altered as a result of applying mitigation measures and increasing wind in the system as the analysis proceeded. Whenever a change is applied to a base case, it is stated in the relevant section and the scope to which the change applies is made clear.

It is important to note that the above four cases are representative cases of important system scenarios. Needless to say that in a given electric power system, there could be a high number of system scenarios that take into account the various demand levels, dispatch scenarios, merit order scenarios, studied contingencies, seasonal variations etc. and in most analytical cases it is almost impossible to replicate and simulate all. Instead, a reduced number of representative cases are formulated, modelled, studied and analysed to draw generalized conclusions. The above four base cases are believed to be representative cases for the Nova Scotia power system in stressing the system in terms of technical limitations with the introduction of increased wind generation.

4.3. Dynamic Models

This section discusses the dynamic models of Nova Scotia system components.

4.3.1. Load

Active power loads in Nova Scotia are 50% constant current and 50% constant impedance. Reactive power loads are 100% constant impedance. As such, the reactive loads are frequency-dependent (since NETFRQ is turned on[5]).

4.3.2. Synchronous Generator

Nova Scotia system has both thermal and hydro generating units. The MVA ratings of thermal units are generally much larger than those of hydro units. The thermal units are modeled using round rotor generator models (GENROE and GENROU) with controls. The hydro units are modeled using salient pole generator model (GENSAL) with controls.

4.3.3. Wind Generation

There are three different types of wind turbines connected to the Nova Scotia power system. These are induction generators (type-2), doubly-fed induction generators (DFIG, type-3) and full converter type generators (type-4). Table 4-2 summarizes the number of wind turbines according to their type and provides the total installed capacity in terms of MVA.

Table 4-2: Existing Wind Dynamic Types in Nova Scotia System

Type	Description	Total MVA
2	Induction Generator	34
3	DFIG (manufacturer A)	122
3	DFIG (manufacturer B)	177
4	Full Converter	268

[5] Checking NETFRQ flag in PSS®E results in network parameters, machine flux models and reactive loads modeled on constant impedance to be adjusted based on local frequency. Frequency dependent load models such as IEELBL or LDFRBL are not used in the NSPI system.

In the course of this analysis new wind generation is added to the base cases. The dynamic model used for these new wind generation is type-4. Figure 4-2 shows the buses chosen by NSPI to connect the new wind farms and their maximum MW output.

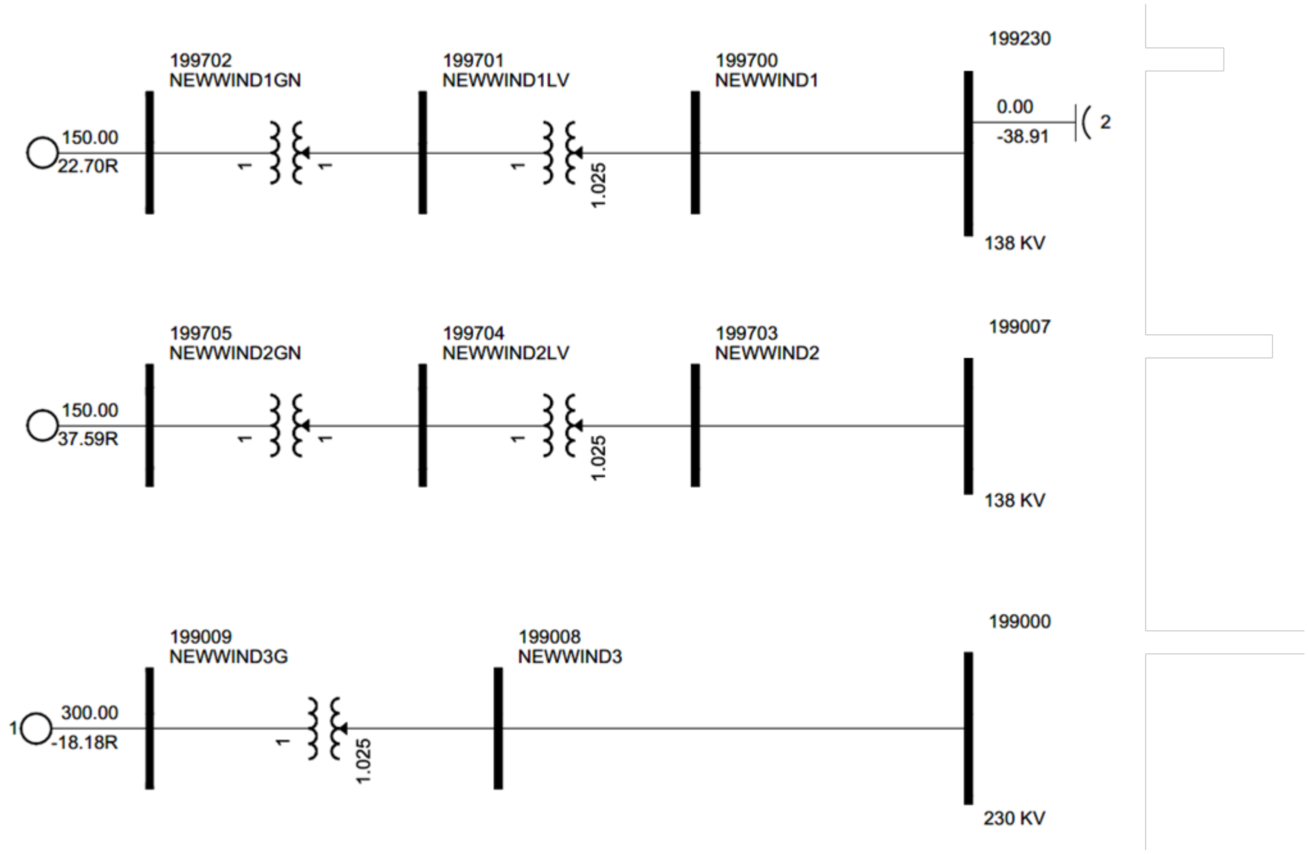


Figure 4-2: Locations for Adding New Wind Generation

4.3.4. Maritime HVDC Link

The Maritime HVDC link has two poles each of which is modeled as two coupled generators as shown in Figure 4-3. The user-defined model that is used to control current injection through these generator pairs is C_ABBL_2OT_MTM [8]. Note that voltage source converter HVDC models the HVDC link as independent generator components in the power flow. These generator components get internally connected through C_ABBL_2OT_MTM dynamic model. The event of tripping a pole is modelled by putting the corresponding generator pairs out of service.

Figure 4-3: Maritime HVDC Link Between Nova Scotia and Newfoundland

4.3.5. Synchronous Condenser (SC)

Synchronous condenser is a synchronous machine without a turbine or load. During normal operation, it can exchange reactive power with the network thereby regulating the voltage at the expense of a small amount of active power consumption to compensate for losses. The voltage control loop of the synchronous condenser provides fast voltage regulation at the connection point. During frequency disturbances, the synchronous condenser exchanges active power with the grid as well by slowing down or speeding up. The energy that is injected into or absorbed from the electrical grid is due to the inertia of the synchronous condenser.

Synchronous condensers are added to the Nova Scotia system as part of this study. Each synchronous condenser is rated at 100 MVA. The dynamic models used for synchronous condenser are salient pole machine (GENSAL) and simplified excitation system (SEXS) with inertia set to 5 s (500 MW.s). This represents a synchronous condenser fitted with flywheel to increase its inertia. Although Nova Scotia has seven combustion turbines, each rated 30 MVA, equipped with a clutch allowing them to operate in synchronous condenser mode, they are not considered to be suitable for this purpose due to their low inertia and high losses.

4.3.6. Battery Energy Storage System (BESS)

Battery Energy Storage Systems bring several advantages such as dispatchability and predictability of renewables. Like synchronous condensers they help with regulating the voltage. However, being inverter-based they do not contribute to the short circuit ratio. Batteries can compensate for the power imbalance caused by a transmission tie trip or a generator or load trip event rapidly, up to their power capability. The batteries also help with the more long-term task of regulation with intermittent wind power.

Batteries are added to the Nova Scotia system as part of this study. Each battery is rated at 100 MW and the dynamic model used for it is EPRI Battery Energy Storage (CBEST) [4]. This model represents a battery which has a large enough storage capacity to be able to deliver its full output of 100 MW for the entire simulation time (typically 20 s). The auxiliary supply signal, PAUX [MW], is either simply a ramp command to inject or absorb power in the shortest possible time or a combination of ramp and PID controller.

4.3.7. Protection

The protection in the Nova Scotia model consists of distance protection (DISTR1) relays, low-voltage load shedding (LVS3BL, LVSHBL) relays, and low-frequency load shedding (LDSHBL) relays. Generator shedding if needed is implemented in the contingency (see Section 4.4). It is noted that there are 5 stages of fast load shedding followed by a final load shedding that is activated after 10 seconds. If all stages are activated, as much as 35% of load will be shed.

4.4. Contingencies

The contingencies applied to each case are design contingencies that put the already stressed system under even more stress. If the transient simulation shows that the system survives the initial shock after applying these contingencies, there is a good indication that it can survive other less severe disturbances.

5. Transient Stability Simulations and Results

This section presents the results of transient simulation studies performed as part of this project. The results are discussed under three subsections: Existing System, System with Additional 345-kV Tie, and System with Synchronous Condenser and BESS.

5.1. Existing System

The base cases in Table 4-1 are studied under existing system conditions to see if 600 MW of wind can be supported. This part of analysis is used to quantify a minimum required number of online thermal units.

Case 01, 600 MW Wind, Light Load, High Import from NB with no Thermal Units Online

Nova Scotia system does not survive the event of tripping the AC ties and becoming islanded from the interconnection. The only online synchronous machines in the island are small hydro units. The total aggregate online inertia in Nova Scotia is 387 MW.s. These generators oscillate relative to each other, resulting in the frequency measured at different buses to change rapidly below and above the nominal value. Since the frequency does not consistently stay below the thresholds set for load shedding, effective load shedding does not happen in this case. The dynamic simulation stops short of reaching the final time indicating numerical problems in the software.

The mitigation for the above situation was obtained by bringing more thermal units online as shown in Table 5-1.

Table 5-1: Thermal Units Added to Case 01

Thermal Unit	Bus Number	MW output
Tufts Cove Unit 3	199169	50
Lingan Unit 1	199001	105
Lingan Unit 3	199003	160

The load in Nova Scotia was scaled up to 893 MW, and the Maritime HVDC link was adjusted to export an additional 100 MW (300 MW total) power to Newfoundland. Following the introduction of the above additional units, the total online inertia in Nova Scotia rose to 2766 MW.s. The system in this case stays transiently stable following the tripping of the AC tie lines. Three stages of load shedding are activated resulting in 150 MW of load being disconnected. The frequency settles at around 59.8 Hz. For comparative purposes utilizing two thermal units, all stages of load shedding get activated, disconnecting about 180 MW of load in order to keep the system transiently stable.

Figure 5-1 shows the frequency at Woodbine 345 kV bus when contingency 1 is applied to the original Case01 and to the revised Case01 with the three thermal units running.

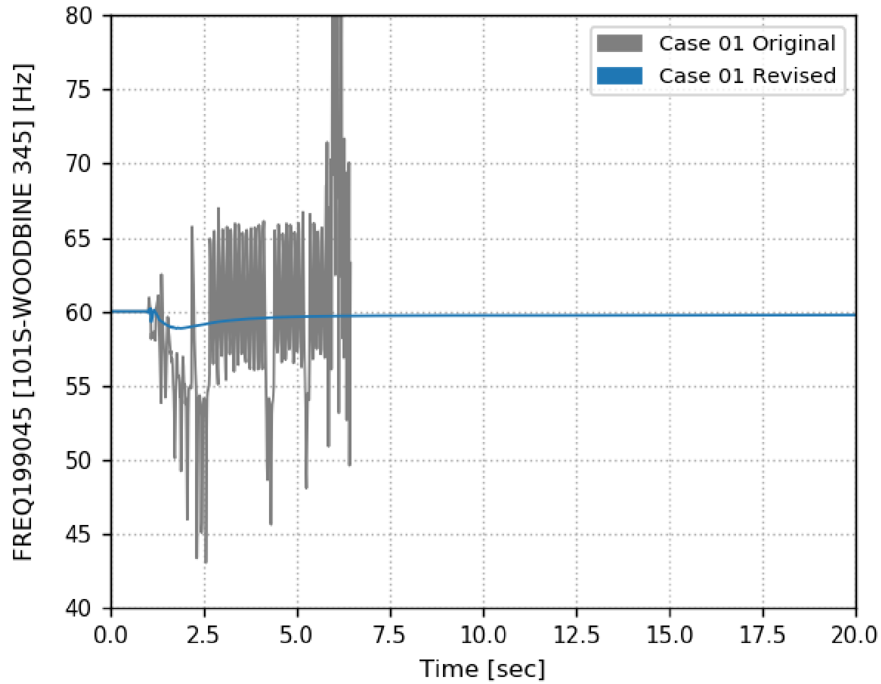


Figure 5-1: Frequency Variations, Case 01, Contingency01_L8001_fault_67N_SPS

A summary of the analysis with Case 01 is presented in Table 5-2.

Table 5-2 Case 01 Adjustment Summary

	Case 01 Original	Case 01 Revised
NS Basic Load [MW]	678	893
NS Total Generation [MW]	670	980
NS Conventional Generation [MW]	85	395
NS Wind Generation [MW]	585	585
NS Thermal Units Online	0	3
NS to NB (+: export) [MW]	-250	-250
NS to NL (+: export) [MW]	200	300
Nova Scotia Online Inertia [MW.s]	387	2766

Case 02, 600 MW Wind, NS Islanded from NB, Two Thermal Units Online

In this case it is assumed that Nova Scotia has successfully separated from the interconnection and is running in an islanded mode. Therefore, the contingencies applied to this case are contingencies within the Nova Scotia system. It was found that none of the applied contingencies cause the system to become unstable. The voltage levels are acceptable and line loadings remain within the thermal limits. Therefore, it seems that once Nova Scotia is operating in an islanded mode, two thermal units can provide enough inertia for it to survive the transients caused by the studied internal contingencies. However, it should be noted that as in all the other cases, the long-term wind fluctuations are not studied here. Sufficient regulating reserve with fast enough ramping capability must be available to be able to control the frequency of the islanded system. Although NPCC requires the system to survive the loss of both poles of the Maritime Link (475 MW or 39% of total load), this study included loss of one pole only.

Case 03, 600 MW Wind, High NS flows, Wind Replacing CB Generation, NS Delivers Reserve to NB

Nova Scotia under system conditions represented in Case 03 is able to support 600 MW of wind. It was found that none of the applied contingencies cause the system to become unstable. The voltage levels are acceptable and line loadings remain within the limits.

It is noted that tripping of the 345 kV tie (L8001) does not cause islanding of Nova Scotia due to a Remedial Action Scheme (RAS) that will prevent the 138 kV circuit from tripping during periods of heavy export to NB. The tripping of L8001 will activate this RAS which will run-back the Maritime Link by 330 MW, or trip two thermal units each operating at or above 150 MW.

Case 04, 600 MW Wind, Summer Peak with One Thermal Unit Online, NB Delivers Reserve to NS

The original base Case 04 under the event of tripping the AC tie causes the system to become unstable. The frequency dips below 58 Hz and all the stages of under frequency load shedding are activated. The load shedding helps recover the frequency, but due to the loss of large amounts of load, system voltages rise too high. This in turn causes the effective load to be increased resulting subsequently in the fall of the frequency. Some further studies were then conducted to check whether the frequency fall can be reduced. In order to achieve, the thermal unit 102S-ACONI (bus 199043) was brought online and this case is designated as Case 04a for comparative purposes. This on its own is not enough and therefore further additional mitigation approaches were checked. The switching-off of some shunt elements are thought to help reduce voltage rise (and hence load increase) and therefore control frequency reduction. With this in mind, the shunts in Table 5-3 were switched off prior to applying the contingency. This scenario is designated as Case 04a Caps Off for comparative purposes.

Table 5-3: Shunts Switched Off to Remedy the Voltage Rise Issue

Bus number	Bus Name	kV	MVAR
199110	1N-ONSLOW	138	50.0
199135	74N-SPRNGHIL	138	36.0
199178	90H-SACKVILL	69	24.0
199340	43V-CANAANRD	138	28.8

Figure 5-2 shows the frequency variation at Woodbine Substation and Figure 5-3 shows the voltage variation at Onslow substation before and after the adjustments to the original base case model.

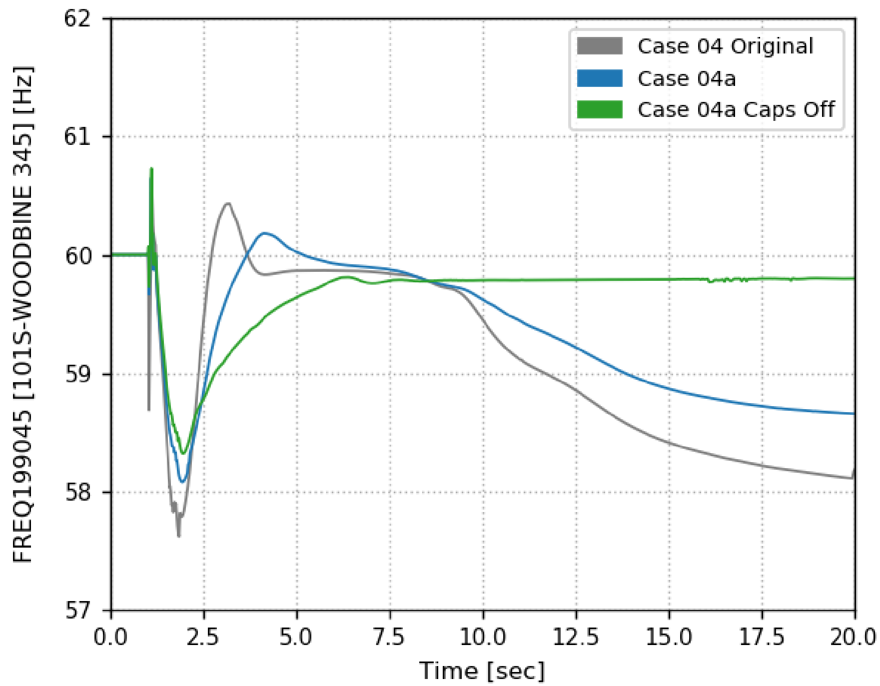


Figure 5-2: Frequency Variations, Case 04, Contingency03_Fault_on_L8001_67N_GP6_SPS

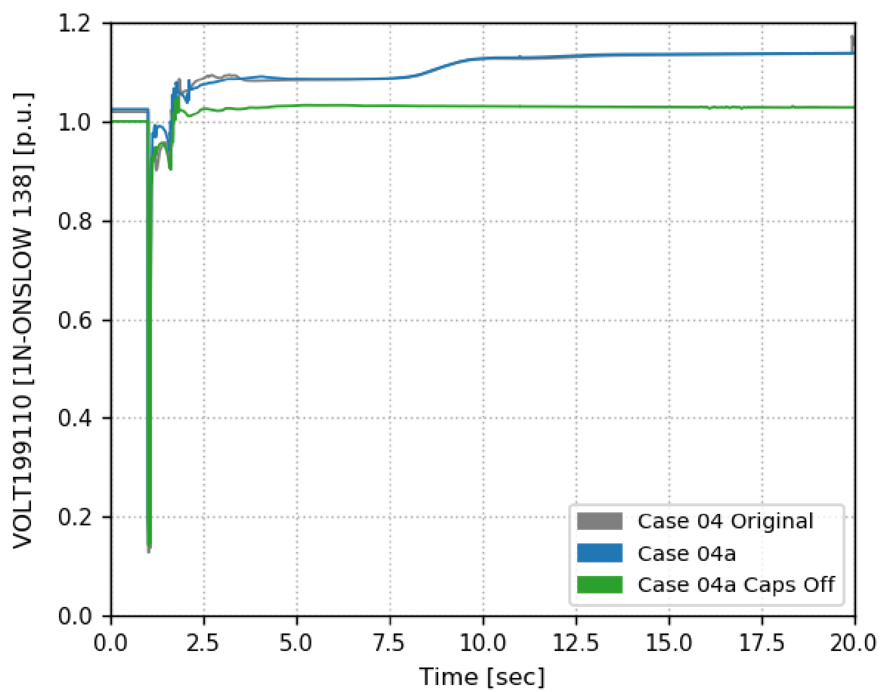


Figure 5-3: Voltage Rise at ONSLOW, Case 04, Contingency03_Fault_on_L8001_67N_GP6_SPS

Table 5-4 shows the adjustments made to Case 04.

Table 5-4 Case 04 Adjustment Summary

	Case 04 Original	Case 04 Revised
NS Basic Load [MW]	1604	1619
NS Total Generation [MW]	787	972
NS Conventional Generation [MW]	202	331
NS Wind Generation [MW]	585	585
NS Thermal Units Online	1	2
NS to NB (+: export) [MW]	-410	-417
NS to NL (+: export) [MW]	-475	-300
Nova Scotia Online Inertia [MW.s]	1347	2280

In summarizing the studies with the system as is and the four base cases, both Case 02 and 03 result in the system being stable following the introduction of 600 MW wind, whereas Case 01 and 04 result in unstable condition following a designated system contingency. However, in both of these unstable cases, existing facility manipulations were able to make the system stable.

Summarizing the case studies, with the changes made in the original cases, and with allowing load shedding to happen it is concluded that the existing system can survive the transients and remain stable while hosting 600 MW of wind generation. Table 5-5 summarizes the observations from transient stability simulations performed on the original base cases.

Table 5-5: Summary of Transient Stability Simulation Results, Original Base Cases

Simulation Case	**Transient Stability Result**	**Mitigation applied**
Case 01	Unstable system, mitigation needed	3 thermal units added
Case 02	System stable	
Case 03	System stable	
Case 04	Unstable system, mitigation needed	1 thermal unit added, 4 shunts switched off.

In order to investigate whether wind capacity can be increased in the existing system Cases 03 and 04 were further examined. Cases 01 and 02 were dismissed because the system conditions represented by them imply that wind will need to be curtailed even if more capacity is added. For the additional studies in Cases 03 and 04, wind was added in proposed locations 1 and 2.

For Case 03 in which Nova Scotia has high inertia and high load, adding wind was achieved by reducing the internal conventional generation. At 700 MW of total wind generation, simulation of the contingencies showed stable operation. At 800 MW of wind one thermal unit was switched off. In this case Contingency01_L8004_fault_101S_NOSPS stops at about 4 seconds indicating transient stability issues.

For Case 04 in which Nova Scotia has high load and high import, adding wind was achieved by reducing the import through the Maritime HVDC link. The severity of tripping one or two DC poles is therefore less pronounced as more wind is added. The tripping of AC tie causes the same amount of MW to be lost and Nova Scotia to become islanded as in lower levels of wind. All stages of load shedding get activated in simulations with 700 MW and 800 MW of total wind generation resulting in 360 MW of load to be shed. It is noted that the control of frequency in Nova Scotia in islanded operation is the main issue. This major issue requires additional system reinforcements to accommodate increase of wind beyond present levels.

5.2. System with Additional 345-kV Tie

For the second phase of the studies, an additional 345kV line between the Nova Scotia and New Brunswick systems were added. The presence of this second tie, reinforces the Nova Scotia system especially under the N-1 contingency of one of the tie lines and hence the system no longer becomes islanded. It is also envisaged that this second tie line can increased the level of wind generation that can be accommodated in the Nova Scotia system. This additional 345-kV tie between Nova Scotia and New Brunswick is shown in Figure 5-4.

Under the base cases of Case 01 and 02, adding wind to Nova Scotia is not feasible assuming the wind needs to be curtailed due to lack of enough load or export limit. Therefore, no studies were performed under cases 01 and 02 and only cases 03 and 04 are used for adding extra wind.

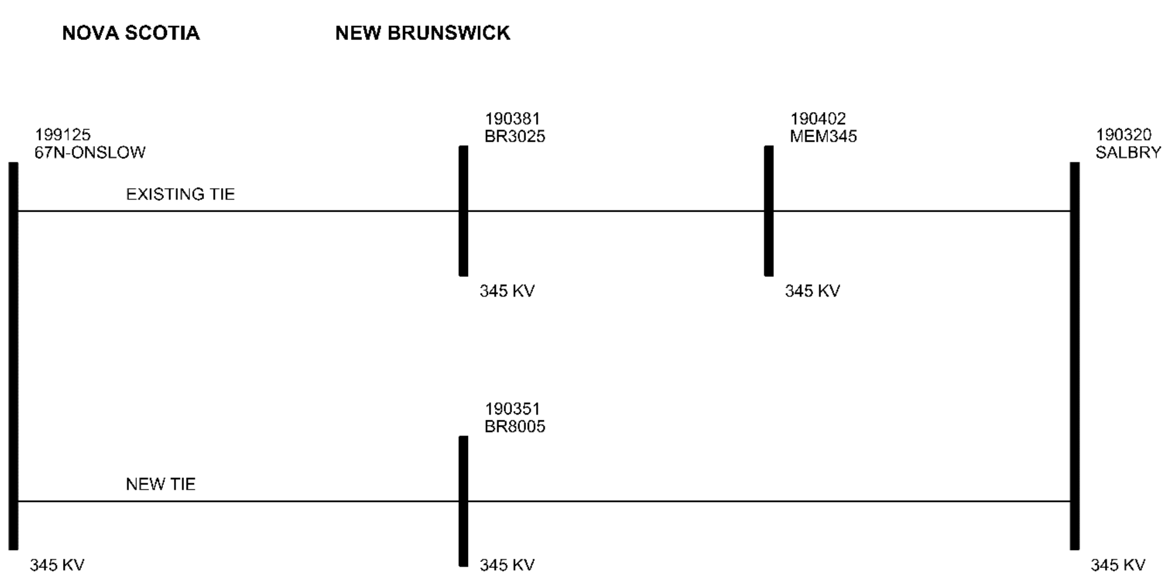


Figure 5-4: Existing and New 345 kV AC Tie Between Nova Scotia and New Brunswick

Case 03, 900 MW Wind

300 MW of additional wind generation was added in proposed wind locations 1 and 2 bringing the total wind generation to 900 MW. A corresponding amount of reduction was initiated from conventional thermal generation to compensate for the additional generation from the wind. As a result the online inertia in the Nova Scotia system reduced from 6666 MW.s to 5869 MW.s. None of the studied contingencies resulted in transient instability. The voltage levels remained within acceptable boundaries and line loadings were all within the thermal ratings.

Case 04, 900 MW Wind

Similar to Case 03, an additional 300 MW of wind generation was added in proposed wind locations 1 and 2 bringing the total wind generation to 900 MW. Thermal generation and Maritime HVDC link power exchange were adjusted to compensate for this additional generation from the wind. No studied contingency caused any transient instability with voltage levels all within acceptable boundaries and line loadings remain within their thermal limits.

Case 03, 1000 MW Wind

Following the successful introduction of 300 MW of wind at proposed wind locations 1 and 2, a further additional 100 MW of wind was added in proposed location 3 (radial with Lingan). Thermal generation was reduced to compensate for the additional generation from the wind. None of the checked contingency cases caused any transient instability. The voltage levels were within acceptable boundaries and line loadings remained within their thermal limits.

As a sensitivity check, wind generation in location 3 was further increased by about 50 MW. With this dispatch and under the contingency of tripping a DC pole, Nova Scotia system loses its synchronism. Tripping of a DC pole causes 240 MW of import to be lost which causes the power export on the AC ties to reduce by about the same amount. Figure 5-5 shows the angle of ACONI G1 (Bus 199043) for three different wind levels. The reference is the angle of machine 126652, 1 (RAV 3) in area 102.

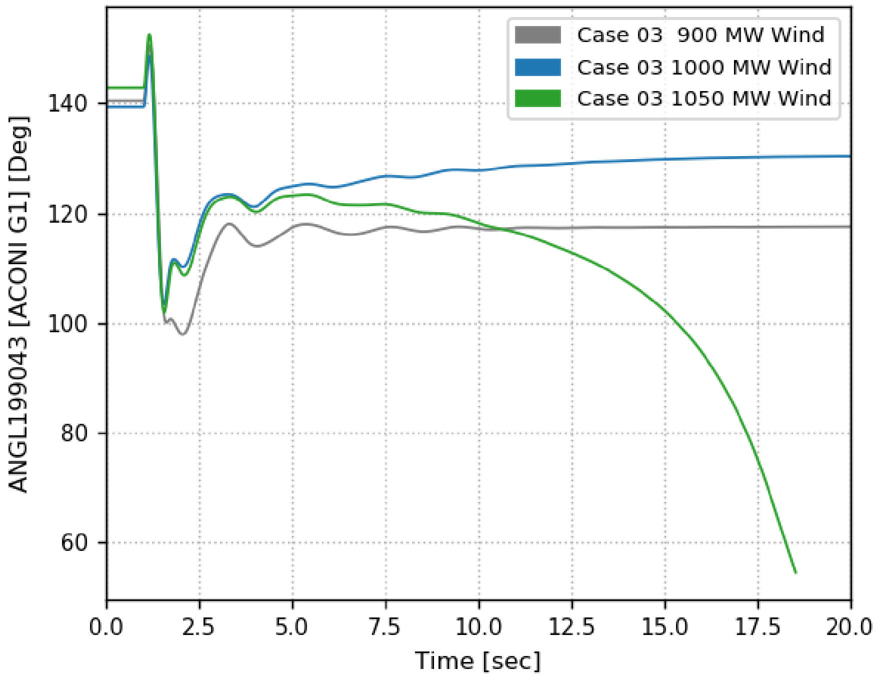


Figure 5-5: Angle Instability, Case 03, Contingency04_Fault_on_ML_Pole2

Figure 5-6 is the plot of several machines in 4 different areas. The reference is the angle of machine 126652, 1 (RAV 3) in area 102. Note that the generators in Nova Scotia (Area 106) and New Brunswick (Area 105) stay in synchronism and drift as a whole with respect to generators in IESO (Area 103).

Therefore, it is safe to conclude that the amount wind generation that can be accommodated within the Nova Scotia system with the introduction of a second 345kV tie-line cannot exceed 1000 MW.

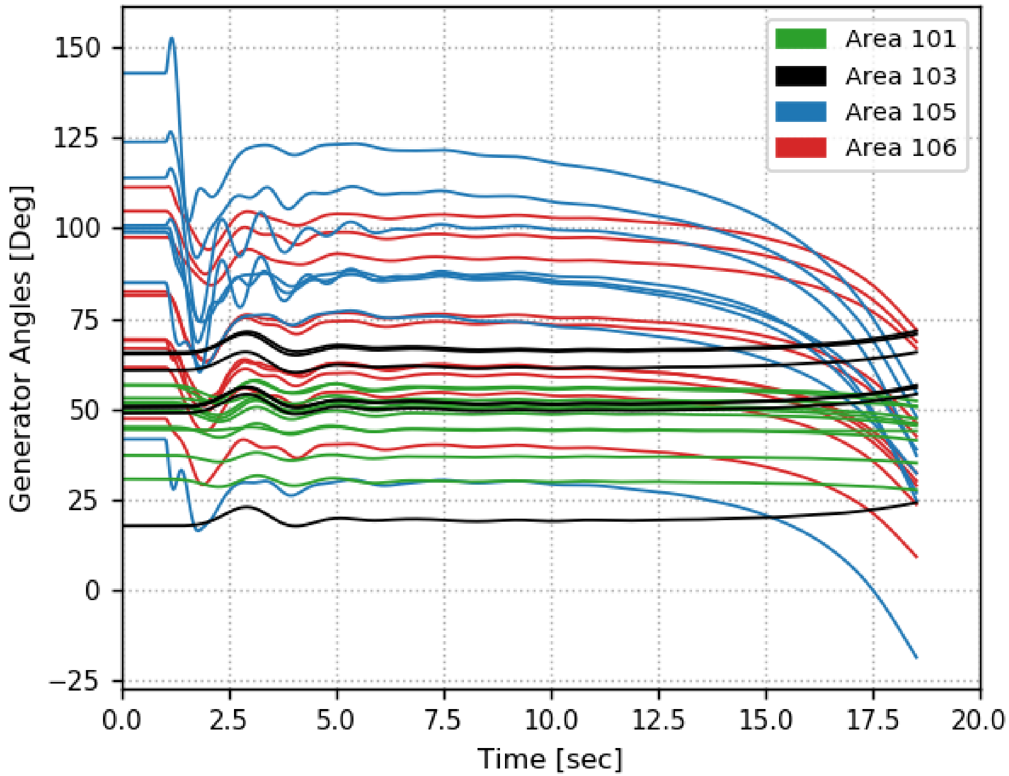


Figure 5-6: Angles is 4 Areas, Case 03, Contingency04_Fault_on_ML_Pole2, 1050 MW Wind

Case04, 1000 MW Wind

A similar approach was taken in Case 04 also with the addition of another 100 MW wind in proposed location 3 (radial with Lingan) in addition to the 300 MW of wind in proposed wind locations 1 and 2 bringing the total wind to 1000 MW. Thermal generation and Maritime HVDC link power transfer were adjusted accordingly to compensate for generation from the wind. None of the studied contingencies caused any transient instability with the voltage levels staying within acceptable boundaries and line loadings remaining within their thermal limits. It should be noted that for Case 04 it was decided not to perform a sensitivity check at 1050 MW wind as Case 03 provided a negative result.

A full summary of the study results with the inclusion of the second 345 kV tie line to New Brunswick is given in Table 5-6. As can be seen, with the inclusion of the second 345 kV tie line, the wind generation that can be accommodated reaches around about 1000 MW with any further increase causing system instability issues and requiring further mitigation measures.

Table 5-6: Summary of Transient Stability Simulation Results, Base Cases with Second 345 kV Tie

Simulation Case	Transient Stability Result with 300 MW additional wind (overall wind is at 900 MW)	Transient Stability Result with 400 MW additional wind (overall wind is at 1000 MW)	Transient Stability Result with 450 MW additional wind (overall wind is at 1050 MW)
Case 01	Not relevant	No study performed	No study performed
Case 02	No study performed	No study performed	No study performed
Case 03	System stable	System stable	System unstable
Case 04	System stable	System stable	No study performed

5.3. System with Synchronous Condenser and BESS

This section summarizes the observations made following the addition of synchronous condenser and BESS to the Nova Scotia system under base case conditions 03 and 04. During the studies wind is increased in steps of 100 MW using the three locations introduced in Section 4.3.3, *Wind Generation*. Synchronous condenser and BESS are added to the ONSLOW substation where the 345 kV AC tie to New Brunswick is connected. The idea behind this choice of location is that the major event of interest which causes under-frequency or over-frequency in Nova Scotia is the tripping of the AC tie, and the system strengthening components are deemed most effective when they provide their contribution (active and reactive power injection or absorption) where the imbalance occurs. It should be noted that for the studies in this section there is only the existing 345 kV tie line to New Brunswick. Figure 5-7 shows the components that are added to the base cases. There are also dynamic models added to the dynamic file as explained in Sections 4.3.5 and 4.3.6.

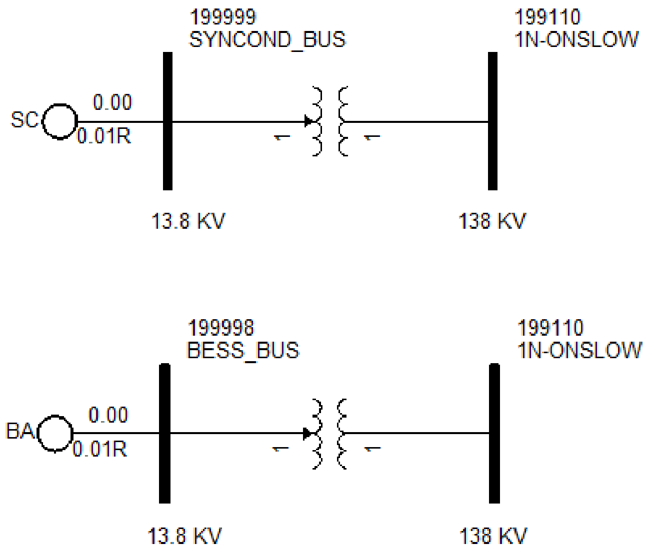


Figure 5-7: Location of Synchronous Condenser and BESS

In order to provide a comparative perspective on the active power output behavior of a SC with that of a BESS a sample study was run. Figure 5-8 shows the active power outputs from the SC and BESS following the tripping of the AC tie into New Brunswick. It is seen that initially the synchronous condenser and BESS both inject active power with the former's response being faster as BESS has delayed response due to the reaction of the controls. However, the output of the synchronous condenser changes with the frequency and becomes negative. For example, with the stator at system synchronous frequency and the rotor at a slower speed, the SC will generate active power and in the opposite case with faster rotor it will absorb active power). In comparison, the BESS is able to maintain the maximum output. It should be noted that in this sample case a ramp controller was used to increase the output of the BESS from 0 MW to 100 MW.

The very fast active power injection from a synchronous condenser which is due to its inertia helps reduce the frequency drop initially. However, by itself the SC does not provide any active power support once the transients have died down. Therefore, if no BESS is used, the gap between generation and load cannot be recovered in the few seconds following the event. The role of BESS in this time frame then becomes essential to reduce the deficit until the slower controllers can respond by adjusting the output of other generators. Or alternatively a more effective reduction in load shedding can be achieved by proper combination of synchronous condenser and BESS.

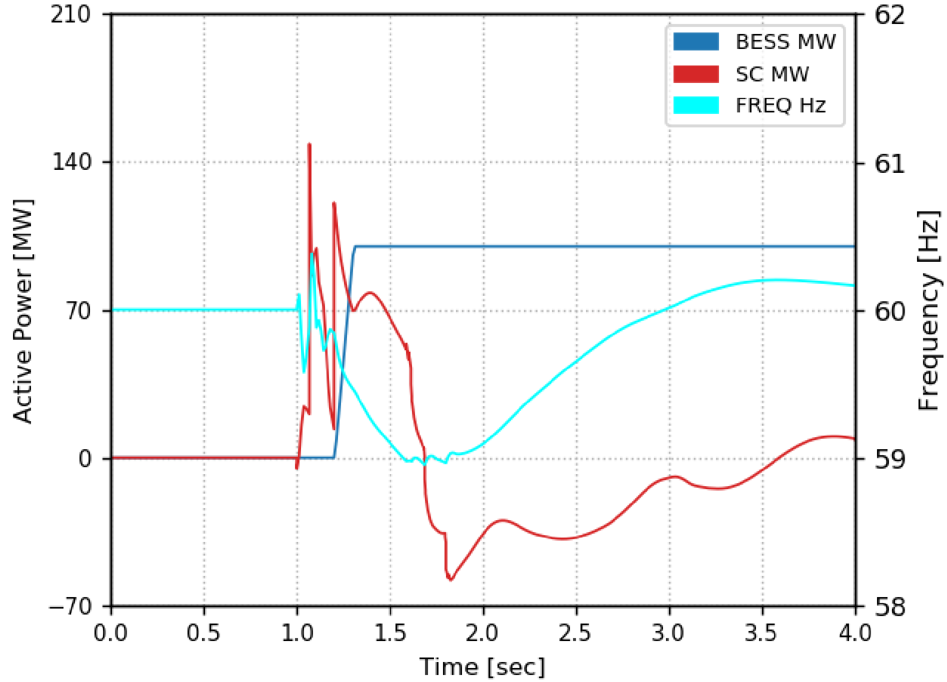


Figure 5-8: SC/BESS MW Output, Case 04a, Contingency03a_Fault_on_L8001_67N_IPM_SPS

The studies with the introduction of synchronous condenser and BESS were performed for each technology being introduced on its own and as a combination. These were introduced at ONSLOW 138 kV and their level was chosen as 100 MVA or 100 MW each. The wind level in both Case 03 and Case 04 was increased up to 1000 MW in steps of 100 MW. It was found that the system remains transiently stable after applying the studied contingencies.

Figure 5-9, Figure 5-10, and Figure 5-11 show the simulation results of tripping the AC tie to New Brunswick with Case 04 at 100 MVA and 100 MW levels of SC and BESS, respectively, either considered alone or together. When both SC and BESS are added, load shedding reaches 306 MW to survive the tripping of the tie.

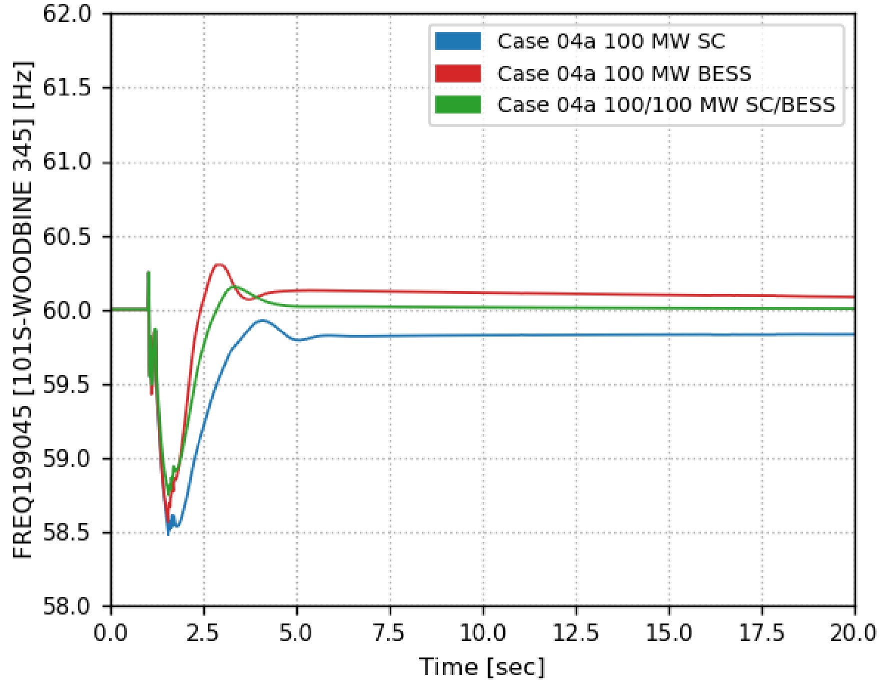


Figure 5-9: Frequency Variations, Case04a, Loss of AC Tie, 100 MVA SC, 100 MW BESS

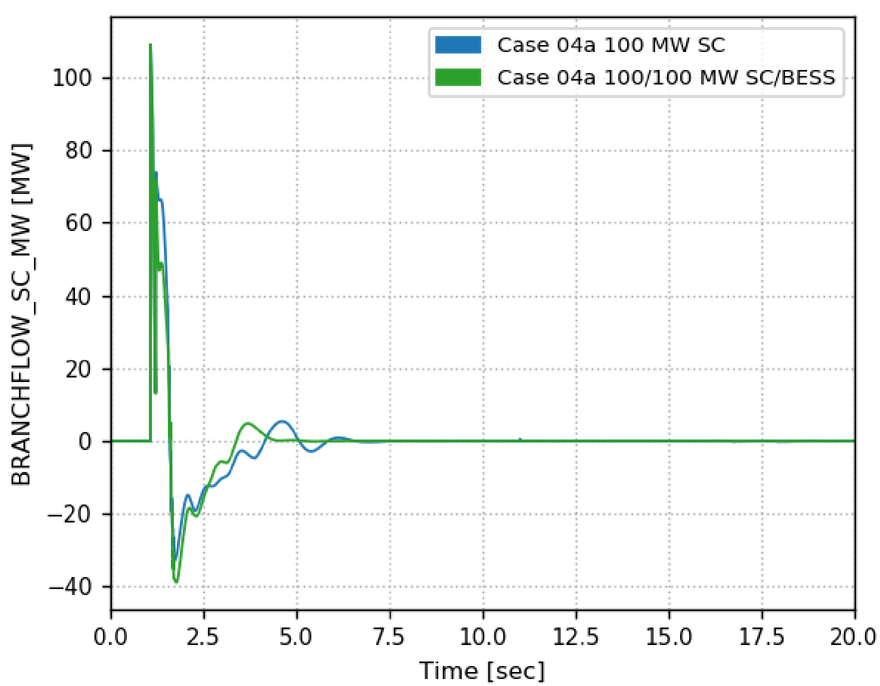


Figure 5-10: SC MW Output, Case04a, Loss of AC Tie, 100 MVA SC, 100 MW BESS

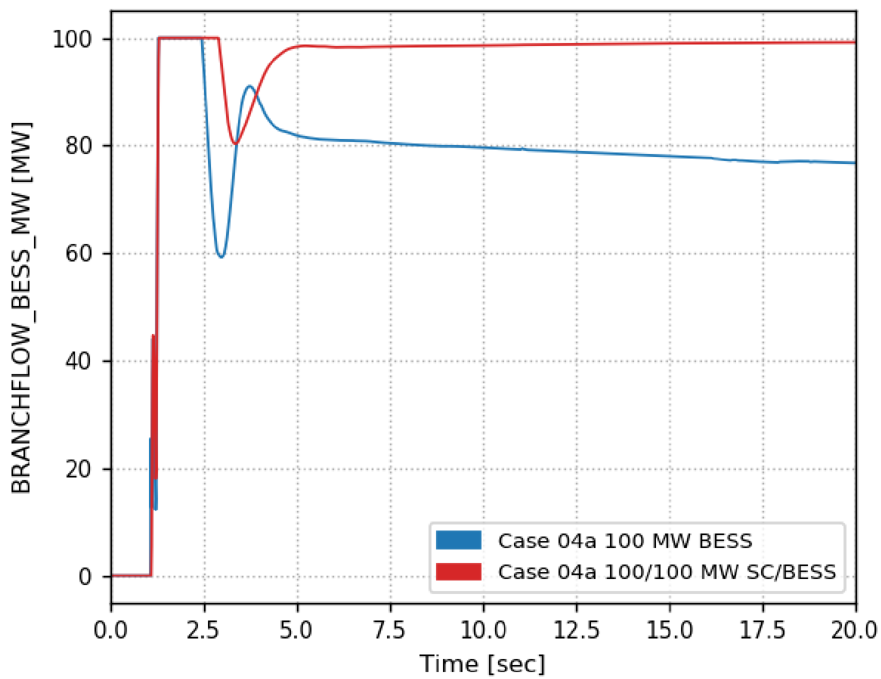


Figure 5-11: BESS MW Output, Case04a, Loss of AC Tie, 100 MVA SC, 100 MW BESS

Increasing BESS rating to 200 MW and the SC to 200 MVA in Case 04, only two stages of under-frequency load shedding become activated when the AC tie is tripped resulting in about 210 MW of load being shed. Figure 5-12 shows the frequency variations at Woodbine substation with three different technology combinations when wind generation is at 1000 MW. The best result is achieved with both the synchronous condenser and BESS in service. Figure 5-13 shows the MW output from the synchronous condenser. Note that the output goes to zero when the transients have died out. Figure 5-14 shows the MW output of the BESS. The controller used for BESS consists of a ramp controller and a PID controller. That is why the BESS output initially goes up to 200 MW, but then reduces to damp frequency oscillations.

Clearly the higher the rating of the SC and BESS, the better the response and less load is shed. Figure 5-15 compares the frequency in Nova Scotia Woodbine substation with 100 and 200 levels of SC/BESS and the level of support obtained with higher rating is evident.

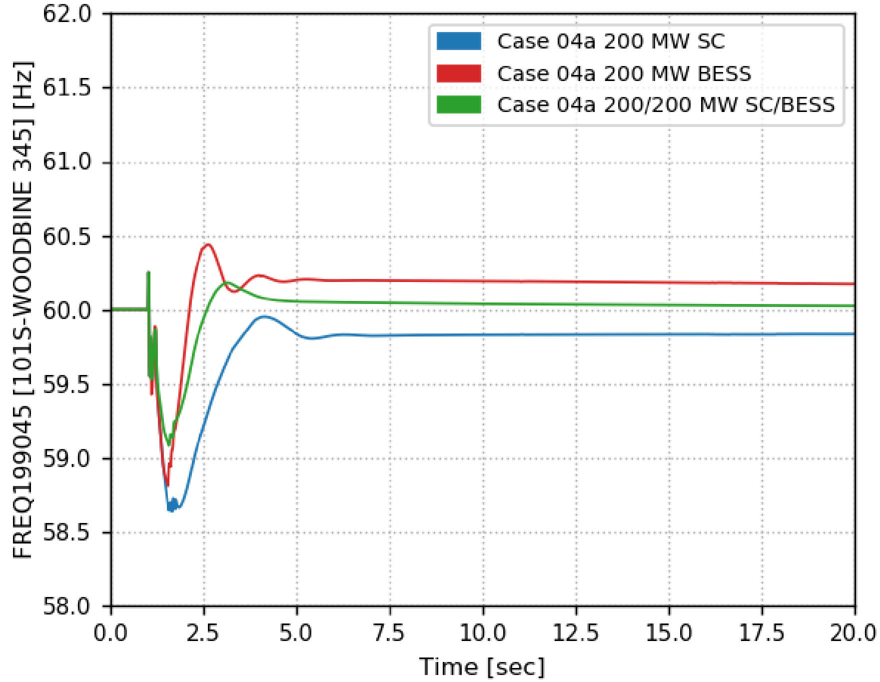


Figure 5-12: Frequency Variations, Case04a, Loss of AC Tie, 200 MVA SC, 200 MW BESS

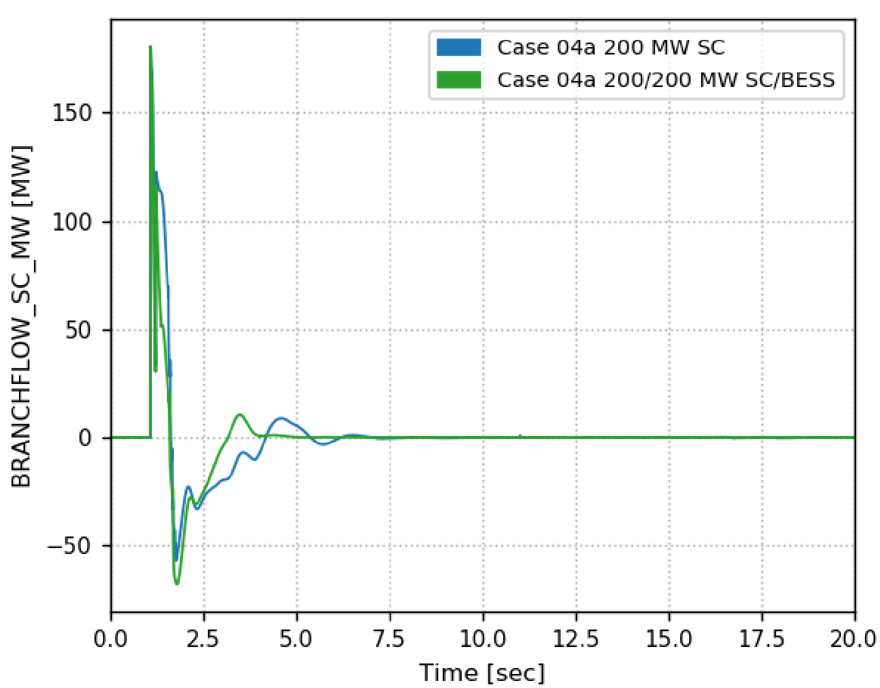


Figure 5-13: SC MW Output, Case04a, Loss of AC Tie, 200 MVA SC, 200 MW BESS

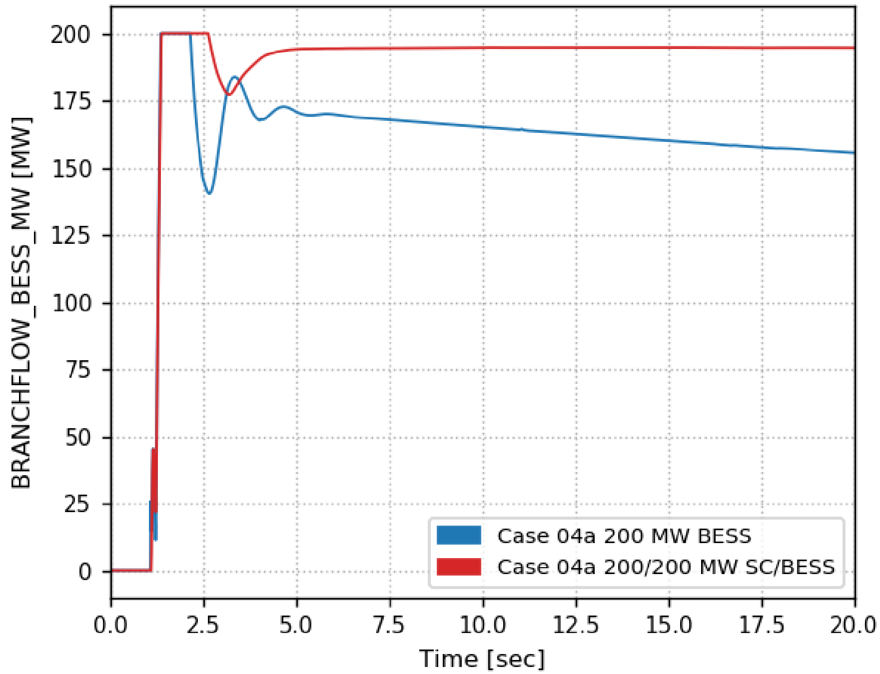


Figure 5-14: BESS MW Output, Case04a, Loss of AC Tie, 200 MVA SC, 200 MW BESS

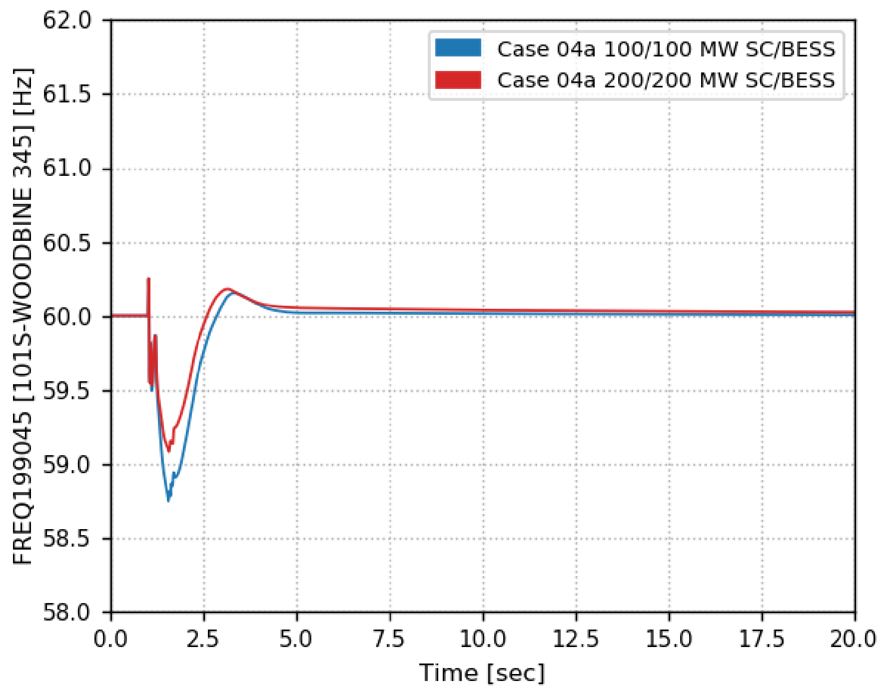


Figure 5-15: Comparison of Frequency with SC/BESS of 100 MVA/MW versus 200 MVA/MW

This analysis added synchronous condensers and batteries at steps of 100 MVA and 100MW, respectively. Although the system is transiently stable in both 100 and 200 levels, a more effective reduction in load shedding was obtained at the 200 level and it was achieved when both synchronous condensers and BESS were considered. The synchronous condenser fast inertial response provides enough time for battery output to ramp up and stay up for the duration of transient study. This has been used as a criterion to choose 200 as the preferred level. Theoretically, it is possible to increase the size of the SC and BESS combination to even higher levels and perhaps eliminate the operation of the load shedding scheme or utilize the load shedding scheme but increase the level of wind generation. However, it is of importance to note that the largest battery installed in South Australia is rated at 100 MW/129 MWh. There are applications in other places to install batteries as large as 150 MW. Given that this technology is new and rapidly changing and, given the large size of both battery and synchronous condenser required to observe the effect in Nova Scotia, it is better to consider this technological solution as a supporting option to reinforcing the system with the addition of a second AC tie. The latter not also provides a proven method of strengthening the system, but it eliminates the most important and critical contingency Nova Scotia system faces.

6. Observations from the Analysis

Table 6-1 shows a summary of all the transient stability studies performed indicating that the limit of wind integration based on the investigated options is estimated to be approximately 1000 MW. This calculated level is based on two distinct system scenarios that represent stressed system conditions but nevertheless the representative number of system dispatch and loading cases could be expanded to check as many operational scenarios as practical. Furthermore, while stability is a critically important parameter for technology considerations going forward, other operating factors may enter into criteria for project selection.

The system as it stands is capable of operating with 600 MW wind with the inclusion of some adjustments, such as maintaining a minimum level of thermal generation under certain conditions and by switching off some shunts to control excess voltage. The analysis indicates that these mitigations are relatively straightforward to implement. Simulations with 700 MW of wind during high load and high internal thermal generation or high import from Newfoundland (cases 03 and 04) show stable transient operation; however, this only suggests that the existing system can accommodate this wind under certain conditions. This result must be interpreted with great care as establishing a precise limit is not possible, and experience has shown that once the AC tie to New Brunswick is lost even with the existing wind levels, controlling of the Nova Scotia frequency in islanded operation is very challenging.

The level of renewable generation could be increased to 1000MW with the inclusion of a second tie to New Brunswick. To refine this limit more dispatch scenarios, more wind locations, and more contingencies might need to be considered. The inclusion of this second tie will significantly reduce the probability of islanding of Nova Scotia. In addition to providing system security against an N-1 criterion to the Nova Scotia system, the inclusion of the second tie could facilitate the export of the excess generation from renewable energy, negating the need to curtail it.

Another observation is that the 1000 MW renewable level that can be integrated with the introduction of the second tie, could also be achieved with the use of other technologies, namely synchronous condensers and battery storage system. However, the results of this study indicate that utilizing these solutions on their own as primary facilitator of renewable energy does not solve system issues and vulnerability of the system to frequency stability issues under the critical New Brunswick tie contingency.

Most controllers of power electronic converter-based generation utilize phase-locked-loop and with reduced short-circuit level their operation becomes more difficult. The study did touch upon the likely effect this may have but did not go into a detailed electromagnetic time domain simulation to establish the full picture with respect to the installed wind generation in Nova Scotia system.

Revision of grid codes is heavily relied on in increasing the penetration of renewables in other jurisdictions. For example, in the case of South Australia more stringent frequency response requirements from wind generation may initially be deemed as limiting these resources, but in the wider view this requirement facilitates connection of more renewables with the system being able to ride through more stressing contingencies. Grid codes are also used to create a wider ancillary market where part of the required services can be procured in a regulated environment, ultimately the market dictating the price of the service. Ireland has extensive work in this area with successful outcomes. Introducing new or amended requirements in grid code is usually followed with strict compliance checks and in both South Australia and Ireland these checks now form part of a structured compliance process for the system users. Checks usually are repeated following changes in generator control settings or following maintenance outages in order to prove capability for operational purposes.

A qualitative analysis of power quality issues that may be affected by (or affect the operation of) large scale inverter-based generation should normally form part of a wider study. A typical issue that is encountered is control of harmonics on the system, among others. In most cases this is done with planning stage analysis and emission limit specification leading to installation of shunt passive filters which shift the issue from one harmonic to another. An increased number of such installations is typically masking wider issues and at worst impacting transient stability. Decreasing short-circuit levels adversely impact system harmonic impedances up until the first system resonance point. It is therefore recommended that issues associated with power quality are also looked into as part of a wider system impact study.

Table 6-1 Overall Transient Stability Study Summary

System scenario	Cases	600 MW Wind	700 MW Wind	800 MW Wind	900 MW Wind	1000 MW Wind	1050 MW Wind
System as is, no topological changes or additional devices	Case 01	Unstable, addition of 3 thermal units makes system stable	No study performed	No study performed			
	Case 02	Stable	No study performed	No study performed			
	Case 03	Stable	Stable	Unstable			
	Case 04	Unstable, addition of one thermal unit and switching off four shunts make system stable	Stable, Caution: Islanded operation at this wind level can be problematic.	Stable, Caution: Islanded operation at this wind level can be problematic.			
Introduce a second 345 kV line to New Brunswick	Case 01		No study performed	No study performed	No study performed	No study performed	
	Case 02		No study performed	No study performed	No study performed	No study performed	
	Case 03		Stable	Stable	Stable	Stable	Unstable
	Case 04		Stable	Stable	Stable	Stable	
Introduce SC and/or BESS	Case 01		No study performed	No study performed	No study performed	No study performed	
	Case 02		No study performed	No study performed	No study performed	No study performed	
	Case 03		Stable	Stable	Stable	Stable	
	Case 04		Stable	Stable	Stable	Stable	

7. Conclusions and Recommendations

Phase 1 of the study looked at the capability of the existing Nova Scotia power system to reliably support the existing 600 MW of installed wind that has been integrated to date. Knowing that the tie to the New Brunswick system is of critical importance in terms of system stability and security, the second phase of the studies looked into the level of wind generation that can be accomodated with the inclusion of a new additional 345-kV tie to the New Brunswick system. The third phase of studies were then performed to establish whether the level of increased wind penetration with the second tie can be achieved by the introduction of other technologies without requiring additional interconnection.

Through simulations of 4 different cases that represent stressed conditions in the Nova Scotia power system and applying several severe contingencies, it was concluded that the existing Nova Scotia power system can support 600 MW of wind generation. The study estabished that while Nova Scotia is connected to New Brunswick, there needs to be at least 3 thermal units online so that in the event of separation from the interconnection, the Nova Scotia islanded system can survive the disturbance. Minimum thermal limits were set based on the loss of a single tie to New Brunswick, with limited support from Maritime Link and no support from wind generation. Therefore, the second tie eliminates the primary rationale behind the minimum online thermal units. However, other services are required for the system which are provided by the thermal units regardless of the second tie option. Those services include:

- Balancing services (tie-line control) to manage fluctuations in load and renewable generation (wind, solar).
- Load following, a longer-term generation control service to manage load pickup from overnight to daytime loads
- Short circuit current and voltage control at a local level (perhaps provided with a combination of synchronous condensers and the second tie).

Even with the introduction of thermal units, a large amount of load needs to be shed to recover the frequency and, in one case, due to light load conditions, the voltages in Nova Scotia rise beyond the statutory boundaries. This, in turn, will have the effect of increasing the load that is voltage sensitive. Hence, in addition to running thermal units, reactive power resources should have sufficient dynamic range in order to control high voltages.

A more general way of quantifying thermal unit requirements is by using the total aggregate online inertia as a measure. The case which established three thermal units as the limit has a total online inertia of 2766 MW.s. It is not possible to define this number as the absolute minimum due to the representative but limited number of dispatch case studies conducted for this report. Therefore, it is recommended that other dispatch scenarios consisting of different combinations of synchronous generators and possibly other technologies be studied to refine this number, which could be used as an equivalent alternative to the minimum number of thermal units.

Noting that the loss of the New Brunswick tie is a major event for the Nova Scotia system the second set of studies considered whether the wind generation can be increased with the introduction of a second tie circuit between New Brunswick and Nova Scotia and if so by how much. These studies indicated that an increase in wind capacity will be possible with the introduction of the second 345-kV tie between Nova Scotia and New Brunswick, and that the system is able to accomodate close to 1000 MW of wind generation. The limiting factor is established as system stability and the final refined figure will depend on the specific location of any new wind generation. Three different locations were examined to add the additional wind. It was observed that if the wind generation goes above 1000 MW, the event of tripping a DC pole which causes a rush of power through the AC tie, might cause the Nova Scotia system to go out of synchronism with respect to another part of the interconnection. Under such a scenario, system separation will take place. Going a step further and tripping both DC poles, system separation takes place at reduced wind generation levels. More detailed investigation is needed to establish specific reason for this behaviour.

The last part of the transient stability study looked at the possibility of accomodating a similar amount of wind (up to 1000 MW) as in the case of the second tie but without the introduction of the second tie. In doing this, two different technologies were investigated; synchronous condensors and BESS. Introduction of 200 MVA synchronus condenser and 200 MW BESS at Onslow Substation, resulted in acceptable levels of load shedding (2 out 6 stages get activated) following trip of the existing tie - significantly less than when the levels were set at 100 MVA and 100 MW of SC and BESS, respectively.

The cases where the only synchronous tie from Nova Scotia to the outside world is lost while importing results in loss of up to 40% of Nova Scotia load through underfrequency load shedding, remaining with a high percentage of wind generation which does not have primary frequency control. Restoring load in such a situation will require additional generation reserve. Therefore, this report recommends that determining reserve capacity to be able to restore load requires further investigation. Considering that the tie to New Brunswick is of the highest significance in terms of system stability, and the loss of the tie dictates most of the planning and/or operational actions, strenthening of this tie with a second 345 kV line becomes crucial and should be considered as the first alternative to explore before the introduction of any other technology. Introduction of technology in addition to the second tie line would bring additional benefits such as accomodating more wind but more importantly system security and flexibility in the changing face of generation mix. The study did not specifically establish the increased amount of wind that can be accomodated with the use of synchronous condenser and battery storage technology in combination with the introduction of the second tie line; this is likely an important area for further investigation.

Some background information on two other systems have been provided in the report in order to draw some similarities with the Nova Scotia power system. Table 7-1 shows the comparison between Nova Scotia system and the South Australian and Irish systems.

Table 7-1: Comparison Between Nova Scotia and Other Jurisdictions

Property	Nova Scotia	South Australia	Ireland
Area [km^2]	52,942	200,000*	84,421
Total Installed Wind Capacity [MW]	600	1809	5000
Total Installed Solar Capacity [MW]	Negligible	1065	Negligible
Total Installed Synchronous Condenser [MW]	0†	0	0
Total Installed Battery Storage [MW]	0	130	10
Peak Demand [MW]	2180	3005	6500
Minimum Demand [MW]	650	1000	2500
Percentage of Minimum to Peak Demand [%]	30	33	38
AC Ties to Neighbors	2 circuit 300 MW import 330 MW Firm/500 MW non-firm export	2 circuits 650 MW import 650 MW export	None
DC Ties to Neighbors	2 poles 250 MW import / pole 250 MW export / pole	1 pole 220 MW import 220 MW export	2 poles 500 MW import / pole 500 MW export / pole
UFLoad Shedding	Used	Used	Used
RoCoF	Not used	Used (3 Hz/s)	Used (0.5 Hz/s)
Minimum Required Total Online Inertia [MW.s]	2766	6000	23000
Ratio of Minimum Required Total Online Inertia to Peak Demand [s]	1.3	2.0	3.5

* Area covered by transmission network

† Nova Scotia has 6-7 combustion turbines (30 MVA each) which can function as synchronous condensers. They were not dispatched in the base cases as they are generally used for dynamic reactive power reserve and quick-start operating reserve. They are also low inertia devices in synchronous condenser mode of operation

It is noted that the online inertia in Nova Scotia is based on the number calculated for the existing system capabilities with limited scenarios and is well below those for the other two systems. This implies that the frequency excursions will be larger for events that cause imbalance between load and generation and is a generic indication of increased vulnerability to lose synchronism under the tie line outage with increased power electronic converter based generation. It is therefore strongly recommended to perform further system studies with wider dispatch scenarios and a defined system development plan to establish a more robust online inertia level.

Load shedding is used in all three systems, however, in South Australia and Ireland load shedding is not relied upon for mitigating the effects of planning contingencies. It is an operational tool and in the case of Ireland demand side units are proven to provide not just load sheding but some other system services.

Rate-of-Change-of-Frequency (RoCoF) monitoring and protection relays are being increasingly used to deal with system frequency issues and in turn facilitate a more planned integration of power electronic converter based generators. The settings of RoCoF relays in South Australia and Ireland need to be adjusted to allow for faster rate of change without tripping in order to accommodate lower online inertia that is a consequence of retiring conventional generators in favor of inverter-based generators. These relays are not used in the Nova Scotia system, therefore the complication that may arise out of their use is not a concern. RoCoF relays cause tripping of equipment (generation, load, etc.) on a predictive basis. Their use can be advantageous in the absense of fast frequency controllers. However, they increase the time and effort for system restoration. Use of fast controllers such as batteries to control the frequency can introduce flexibility to the use of RoCoF relays in relation to frequency stability. In Ireland, the use of RoCoF relay setting is being inceared to 1 Hz/s in addition to fast frequency response requirements that are being sourced from the market as an ancillary service.

South Australia is seeking to construct a second 330 kV AC double circuit tie line from the mid north region of South Australia to Wagga in the neighboring state of New South Wales. The benefits of this interconnector are increased system security in South Australia, considered essential given the increasingly credible loss of both circuits of the existing AC interconnector, as well as facilitating increased penetration of renewables. It is of interest to note that in terms of interconnection with neighboring grids, South Australia is similar to Nova Scotia and the second AC circuit as planned is comparable to the second New Brunswick tie line. However, there is difference between the two systems in terms of reliance on the interconnection to neighboring grids. Loss of the single tie between the Nova Scotia and New Brunswick power systems has a pronounced effect on the technical performance of the Nova Scotia system and without resolving this contingency, the options to increase the level of renewable integration in Nova Scotia are limited. The loss of the AC tie in the South Australia case does not have similar pronounced consequences in terms of system technical performance.

Given that a minimum number of synchronous machines need to be online for frequency control and assuming Nova Scotia load remains practically unchanged, if the size of the export market cannot be increased as more variable renewable energy is installed, the renewable generation would have to be curtailed. This economic tradeoff can be examined in an exercise such as an Integrated Resource Plan.

The following are the recommendations for system reinforcement based on this study:

1) The existing system renewable integration level is close to 600 MW. While simulations with 700 MW of wind show stable transient behavior in the event of tripping the New Brunswick tie under certain system conditions, it is not recommended to assume this as a firm limit. The reality is that establishing a firm limit by looking into a limited number of system conditions and scenarios is not possible, and there are already indications from the past events that frequency control of Nova Scotia in islanded operation is very difficult.
2) In terms of benefits derived from adding a second tie versus adding synchronous condenser and battery energy storage, the former reinforcement measure is superior, because it eliminates the islanding of Nova Scotia in the event of losing a single AC tie.
3) With either a second tie or combination of synchronous condenser and battery energy storage the renewable integration can be close to 1000 MW. This result was obtained base on the transient stability simulations of the representative system conditions and representative contingencies.
4) Exploiting both a second tie and technologies such as synchronous condenser and battery energy storage will increase system security and reliability in different operating scenarios including in islanded mode.

In general, following the limited studies performed, this report recommends that this study be expanded in order to establish a system security level commensurate with increased wind generation. This should be based on well-defined system topologies which include the second tie as a starting position. Most studies of this nature are based on the criterion of establishing maximum renewable generation penetration with minimum system reinforcement. This can be seen as a balanced approach in terms of system development. However, it is noteworthy that the Nova Scotia system is rather unique in its behavior to the existing New Brunswick tie contingency and hence any study without the second tie appears to be counter intuitive. Therefore, in continuation to the work done here, PSC would recommend to:

1) Expand the existing study: The study should be expanded initially to capture wider dispatch and loading scenarios. The expanded study should then look at the possibility of introducing specific technology measures to understand the effect these might have especially with regards to the time frame (fast frequency response vs primary or secondary frequency response), location and level.
2) Provision of enhanced studies: The above expanded studies should be enhanced further with time domain simulations in order to establish fast frequency response requirements as well as other areas such as response and ride-through under depleted short-circuit ratios.
3) Expand the set of contingencies studied: Only a select set of contingencies were included for expediency for this study. Planning studies are normally conducted with a full set of steady-state and stability contingencies. Of particular note is the requirement to survive both poles of the Maritime Link (net 475 MW).

4) Establish best route for services: Combining the two studies above, determine what level of ancillary services can be obtained via grid code enhancements from contracted Power Producers.
5) Impact on power quality study: Increased level of power electronic converter based generation is known to bring other issues into the system, one of the most prominent one being power quality. This area usually has two aspects; the effect power electronic based generation has on the level of power quality expected at system level and the probability of power electronic converter based generation operating reliably in such an environment. A parallel study to the above should look at the impact of increased renewable generation on the power quality at Nova Scotia system. An emerging area of concern relates to control interactions among power electronic devices as well as between power elecrtonic devices and other system devices (series capacitors and generator turbines) especially at sub-synchronous frequencies. The interaction covers possibilities between HVDC and FACTS devices and wind turbine generators. The possibility of such interactions should be investigated as system characteristics come into effect.

8. References

[1] A. Halley et al "Effects of increasing power electronics based technology on power system stability: Performance and operations", CIGRE Science & Engineering Journal, Vol 11, June 2018.

[2] "Nova Scotia Power Renewables Integration Study Detailed Scope", PSC report, Revision 4, March 25 2019.

[3] "Integrating Inverter-Based Resources into Low Short Circuit Strength Systems, Reliability Guideline", NERC, Decembe 2017.

[4] "PSS®E 33.5 Model Manual", Siemens Power Technologies International, October 2013.

[5] "All Island TSO Facilitation of Renewables Studies", EirGrid/SONI Report.

[6] "DS3 System Services Protocol – Regulated Arrangements", EirGrid/SONI, December 2017.

[7] "RE: Vestas Wind Turbine Generator ans PSS/E simulation model capability for reliable operation at low Short Circuit Ratio", Public letter by Vestas, November 1, 2017.

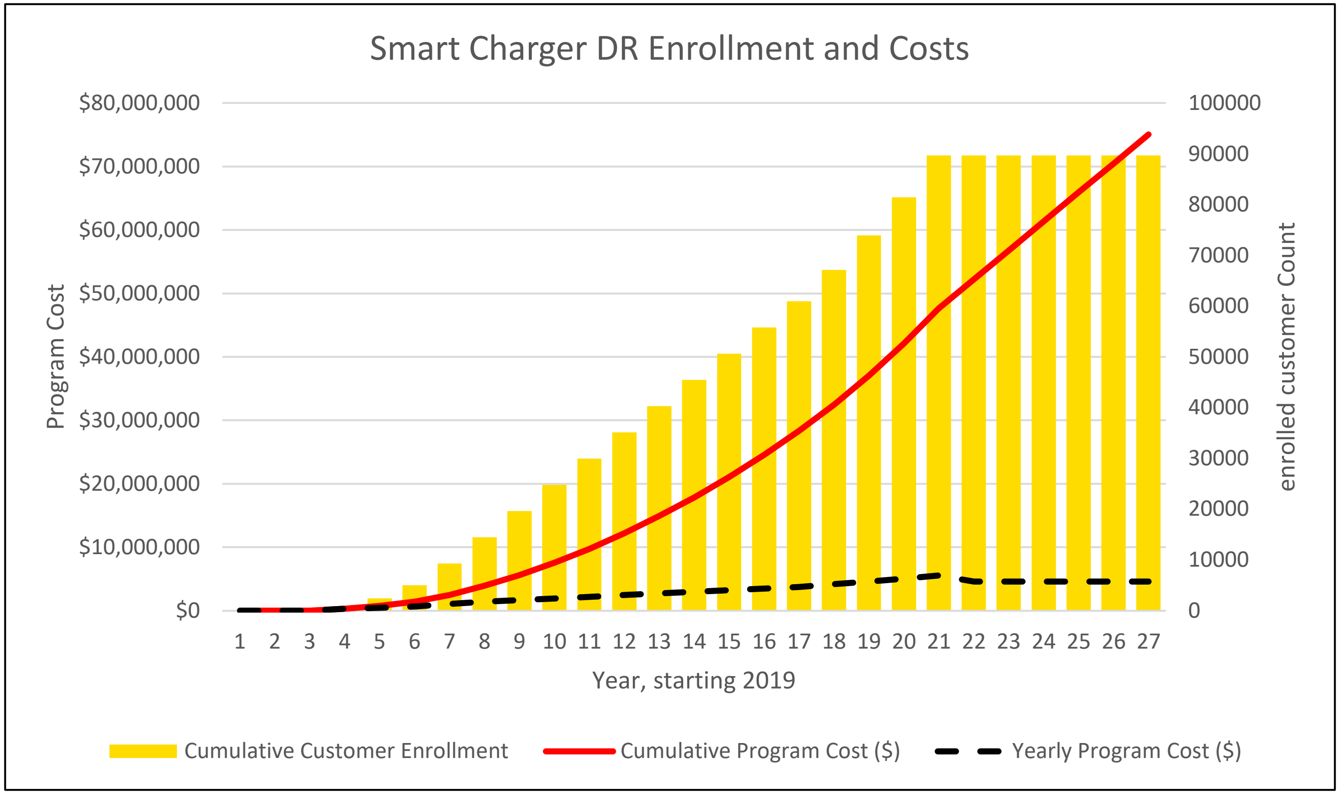
[8] "User guide PSSE HVDC Light Open model Version 1.1.11", ABB document 1JNL100155-617 Rev. 02, 2011.

Demand Response Assumption Summary

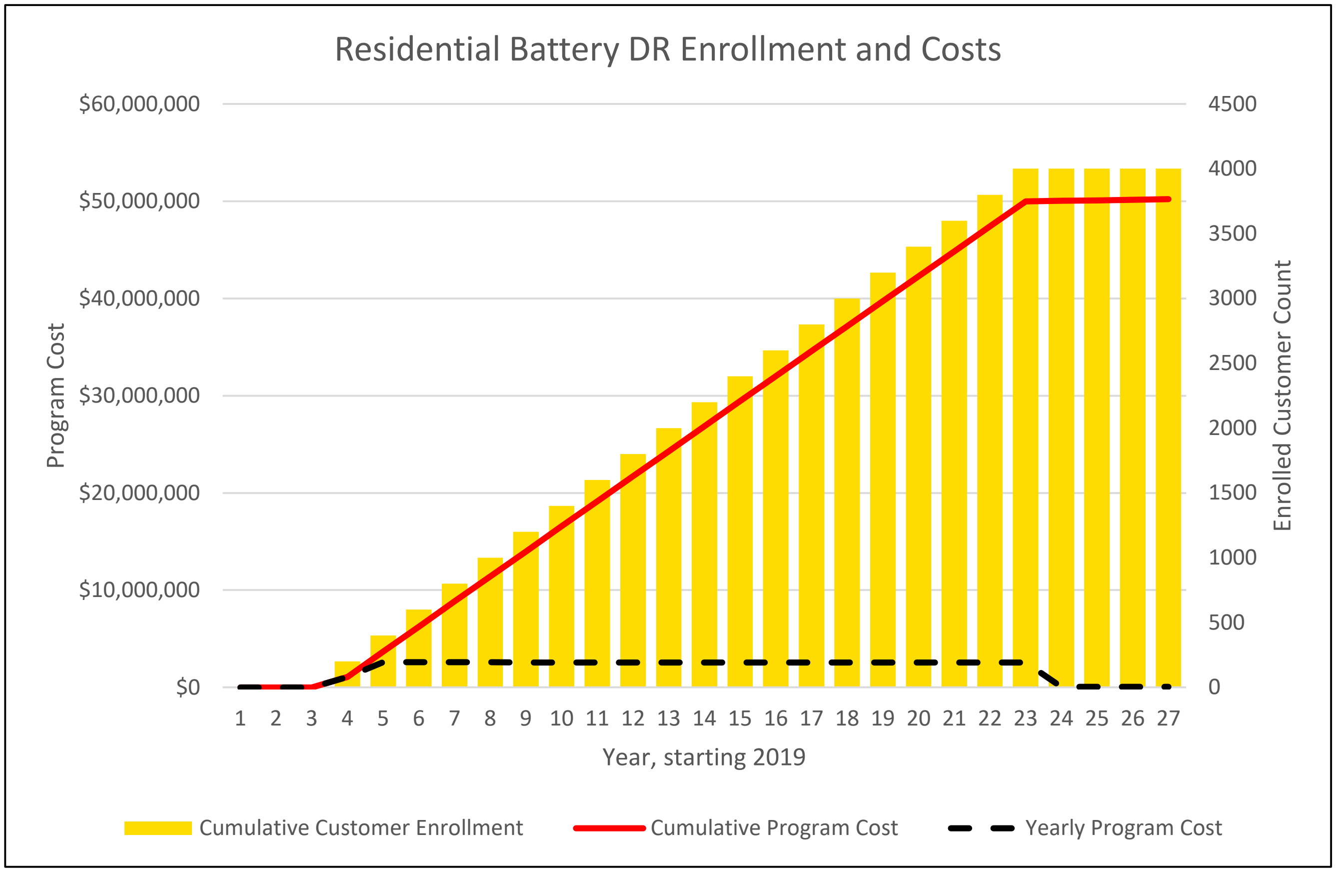
Device	Program	Peak shaving potential (kW/device)	Customer Incentive [1]	Participation Scenario (in year 25)	NSP Total Program Costs (25-yr)
Water Heater	Controller installed on customer WH and used during peak shifting events	0.5	$25 enrollment, $25/yr when compliant to program criteria	Cumulative 50,779 participants (10% of market), 27 MW peak shaving potential	$1.49M/MW
EV Supply Equipment	Customer owned and installed EVSE with peak shifting participation incentives	0.7	$150 enrollment, $50/yr when compliant to program criteria	Cumulative 89,704 participants (70% of market), 63 MW peak shaving potential	$1.19M/MW
Residential Battery	Customer contribution comparable to diesel generator installation, utility control for up to defined number of system peak events	2.5	$2500 customer contribution, Balance of battery cost covered by NSP and funding where available.	Cumulative 4000 participants, 6.25 MW peak shaving potential	$8M/MW

[1] Customer behavior-based peak shifting also through residential time of use, commercial time of use, and critical peak pricing rates.

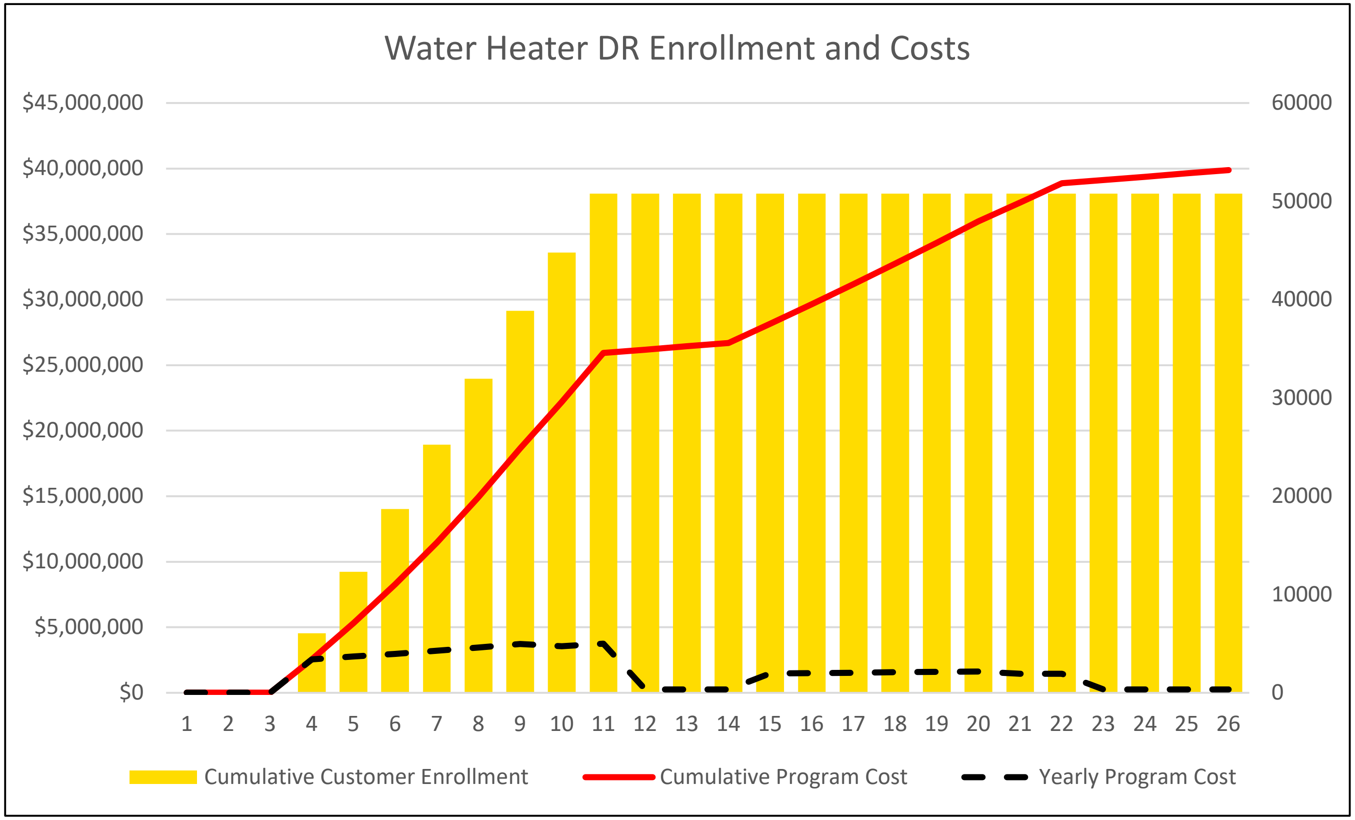
EV Supply Equipment DR Enrollment and Costs



Battery DR Enrollment and Costs



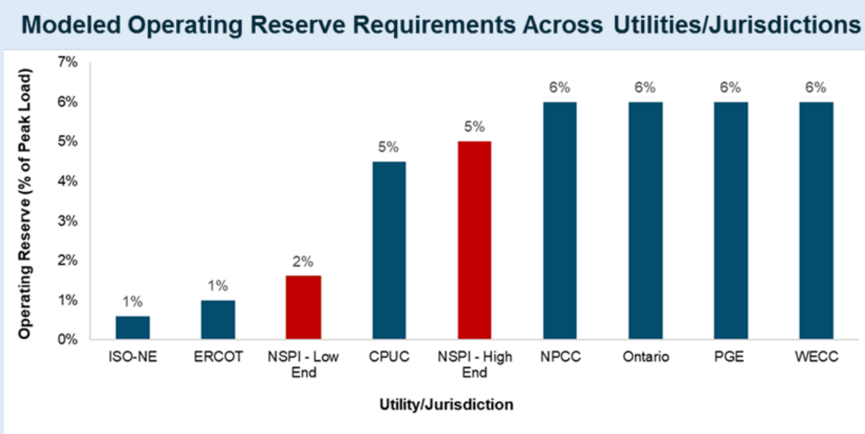
Water Heater Control DR Enrollment and Costs



Appendix A:
Technical NSP Responses to Stakeholder Questions/Comments

Topic 1: General IRP		
#	**Party**	**Question/Comment & Response**
1.1	E1	The Federal government released a draft of new national clean fuel standards, including liquid fossil fuels and solid fossil fuels. Will these regulations be considered for the IRP modelling, assuming there are impacts to NS Power? (although not enacted, NSP should consider the impact of the regulations as drafted to its overall IRP sensitivities)
		Yes, these standards will be considered in the IRP Modeling; the details will be proposed in the Assumptions Development phase.
1.2	Envigour	At least one utility in Nova Scotia (Berwick) is piloting a regime where commercial and residential customers will have renewable generation, storage, and control systems to direct the production of electricity to and from the battery/grid/customer use. The pilot was a winner in the recent Canada-UK Power Forward Challenge. The pilot is setting out to prove the cost and benefit of such systems. If these technology packages (combined to deep efficiency retrofits) prove attractive to customers, they may significantly reduce the load requirements for customers able to afford the capital costs. Will the IRP process deal with the risks and benefits from such customer choices/utility opportunities? And if so at what stage and will there be an opportunity to introduce evidence on such matters?
		NS Power welcomes input in the Assumptions Development and Analysis Plan phase of the IRP to develop and test assumptions for distributed energy resources (DERs).

Topic 2: Planning Reserve Margin (Capacity Study)		
#	**Party**	**Question/Comment & Response**
2.1	Bates White	...we recommend that NSPI apply more conservative – i.e., lower – PRM values in its IRP evaluations… It is our view that the IRP process should be focused on ways to minimize the costs imposed on customers, including costs associated with being unnecessarily long on capacity. Given the ongoing, rapid changes in resource technologies and costs, we believe there may be more risk in pursuing a resource plan that locks in excess capacity than in pursuing one that maintains flexibility to take advantage of future resource options.
		As discussed in Section 3.2.1, a lower Planning Reserve Margin or maintaining lower total firm capacity on the system does not necessarily translate into lower costs. The portfolio optimization process considers other factors such as emissions constraints and energy economics, many of which could result in a portfolio that is cost optimized at a higher "realized" PRM than the specified minimum (i.e. hold excess capacity with resultant lower costs). For example, in the Synapse GUO modeling, all optimal portfolios had excess capacity, as excess capacity often results in economic energy access and/or emissions constraint relief. Notwithstanding the above, a lower PRM could result in lower costs or flexibility benefits, with a tradeoff of potential changes to reliability, as described. NS Power anticipates

		iterating on the PRM calculation for certain IRP portfolios to inform potential changes to the existing PRM. The "base case" PRM to be used for initial IRP evaluations will be established in the Assumptions Development phase.
2.2	Bates White	NSPI should clarify and reconcile E3's reserve definitions and assumptions in conducting its analysis and reaching its conclusions with reserve types that are required by NERC/NPCC and with those categories of operating reserves discussed in our Audit Report.
		Jurisdictions/utilities have varied requirements and methodologies for modeling operating reserves (OR) for the purposes of establishing the Planning Reserve Margin as there is no specific OR quantity mandated by NERC/NPCC. E3 has conducted a jurisdictional scan which shows that many jurisdictions maintain OR when assessing resource adequacy in their planning models (e.g. WECC, ERCOT). As illustrated in **Figure A-1** below, the range of OR calculated in the Capacity Study is consistent with other jurisdictions. ***Figure A-1: Jurisdictional Scan of OR Requirements for PRM Studies***  Planning reserves represent the total available capacity to the system which can be used to serve load or meet operating reserve requirements. Higher planning reserves increase the reliability and lower planning reserves decrease the reliability. Operating reserve requirements should not be thought of as analogous or similar to planning reserves but rather should be more aptly compared to load, given that increases in either value will lead to an increase in required planning reserves. Higher loads generate higher planning reserves and higher operating reserve requirements generate higher planning reserves. E3 believes that the higher operating reserve requirement is the most reasonable base case (corresponding with a 21% PRM) but also presents the lower operating reserve requirement as a lower-bound alternative. Both operating reserve requirement cases used in the PRM analysis are less than the total operating reserves NSP must carry (spinning, 10-minute, and 30-minute). For reference, NS Power is required to maintain 243MW of 30

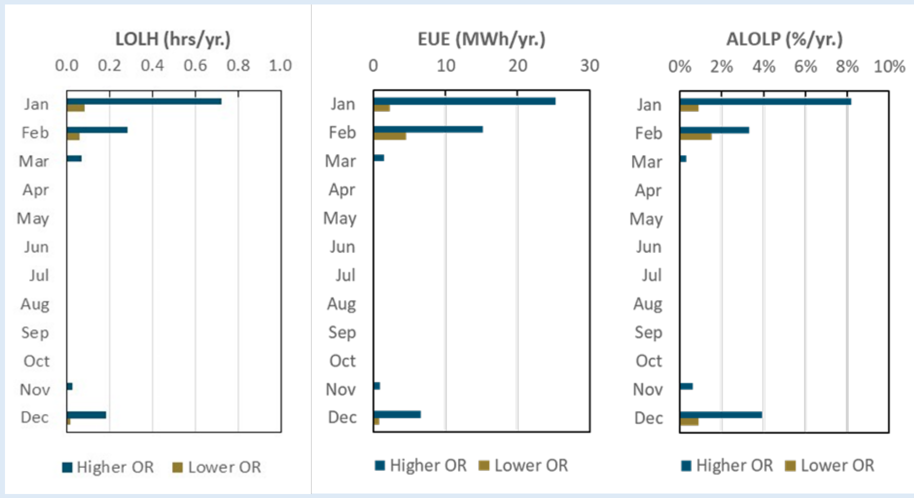
		Minute Operating Reserves. The lower bound OR estimate (33MW) represents 14% of total OR, while the upper bound 100MW represents 41% of total OR. The 100MW reflects the level at which it can be assumed for planning purposes NSP would begin to shed firm load in a reliability incident.
2.3	Bates White	We understand that certain E3 inputs – DAFOR, maintenance schedules – see Table 4 on page 24 and Table 9 on page 29 – came from NSPI. We would like to confirm that the data provided by NSPI is consistent with the data used in the BCF update proceeding (M09288) for all relevant years.
		Relevant data from Tables 4 and 9 in E3's Capacity study and noted primary statistics are consistent with the data from the BCF proceeding (e.g. DAFOR, Availability Factor, Unit Capacity). NSP notes that the BCF modeling utilizes Plexos, which is a mixed integer programming model that optimizes unit commitment/dispatch to meet load and ancillary service requirements at minimum cost, subject to a number of operating constraints. As detailed in Section 2.1 of Attachment 17, RECAP is a loss-of-load-probability model, with the primary objective of calculating reliability metrics (units are dispatched for the purposes of reliability, not economics). Where applicable, primary data sources (or assumptions) are consistent between the two models.
2.4	SBA	The SBA believes that the PRM Study should include expanded analysis of interties. The draft PRM Study included conservative assumptions related to tie benefits from interconnections with New Brunswick and Maritime Link. In the example of New Brunswick, E3 assumption no tie benefit, assuming that New Brunswick is likely to experience resource shortages coincident with Nova Scotia. This assumption should be based on study and analysis of historical shortages, as well as reasonable forecasts of system changes in the future. By relying on conservative assumptions, NSPI may be failing to recognize the reliability value the interconnection can provide and therefore over planning for capacity need. A more detailed study of the potential benefits of the interconnection would allow for a more comprehensive assessment of the costs and reliability risk of future resource decisions.
		As per Section 3.3.5 page 45 [Imports] of the Capacity Study: "However, despite this transmission capability, NSPI only relies on 153 MW of firm capacity over the Maritime Link due to the contracting that would be required to increase this. While energy may be imported through these interconnections, only imports with specifically contracted firm capacity can have a non-zero ELCC". The issue with the existing intertie is firm transmission availability. Firm transmission capability is the amount of electricity that can be delivered in a reliable manner after consideration of surrounding system loads, voltages and stability conditions. Non firm transmission is the additional capability that can be used for energy delivery when available but is subject to curtailment under different system conditions. In order for the NB Tieline to be accredited as valid firm capacity in Nova Scotia and contribute to NS Power's adequacy obligations under NERC reliability standards and NPCC reliability criteria it is necessary that a

		commercial/contract for firm capacity be in place and that it can be delivered via firm transmission. The current lack of available firm transmission (Long Term Firm or LTF) capacity to import into Nova Scotia at the New Brunswick interface limits the delivery of capacity to Nova Scotia. There is currently zero remaining LTF Capacity and limited (up to 100MW) Short Term Firm (STF) capacity on the NB tieline, which can only be reserved on a daily or monthly basis.
2.5	SBA	The PRM Study should be clarified regarding the interaction between planning and operating reserves. The draft PRM study concludes that the PRM should be 17.8-21% depending on the amount of capacity held out for operating reserves. The relationship between operating reserve level and reliability is not sufficiently discussed in the study. The PRM study does note that the model will shed load before allowing the level of operating reserves to dip below the threshold in order to avoid significant grid issues (p. 40), but these issues are not described or explored in the study, so there is insufficient information for stakeholders to assess the material difference between a 17.8% PRM and 21% PRM future.
		Please refer to response 2.2.
2.6	SBA	The SBA notes that the ELCC analysis should be modified to capture anticipated changes to load shape over time. The ELCC calculations are conducted based on historical load shapes. These load shape assumptions appear to have a significant impact on ELCC values, particularly for storage and DR resources at higher penetrations. The study should conduct sensitivity analysis assessing the impact of shifting load shapes with electrified heat, transportation, and with greater demand flexibility and dispatchability. This analysis could show a higher (or lower) ELCC for these resources, thus impacting resource planning outcomes.
		NS Power agrees that different load shapes associated with electrification, DERs, DSM, etc. could impact the ELCC of dispatch limited resources. NS Power anticipates iterating on the Capacity Study for certain IRP Portfolios to provide additional insights into impacts on this reliability criteria. More detail on this approach will be proposed in the Analysis Plan phase of the IRP.
2.7	E1	Why are there no transmission constraints assumed in Nova Scotia [in the Capacity Study]?
		As is consistent with most resource adequacy analyses and PRM studies across North America, this analysis focuses on the availability of all resources relative to the total load of the NSP system. To the extent that there are additional factors such as transmission constraints that must be considered, those would be captured through a separate analysis such as a power flow analysis designed to specifically analyze that issue. The computational complexity associated with modeling this factor would detract from the ability of the RECAP model to analyze the large number of system conditions that are necessary to accurately measure the reliability of the NSP system and the ELCC of individual resources.
2.8	E1	Would reserve requirements change after the impact of DR is considered?
		In E3's modeling, DR does not affect the PRM, given DR is treated as a

		potential supply-side resource. In general, the NSP system has both planning reserve and operating reserve requirements that are needed to maintain reliability. DR is one resource that can contribute to these requirements, and the critical issue is correctly measuring how the DR resource can contribute in terms of ELCC. The nature of the resources being used to meet the PRM (thermal vs. renewables vs. storage vs. DR) should not impact the total planning or operating reserve requirements but the contribution of these resources toward these requirements (as measured in ELCC) can vary significantly.
2.9	E1	Is NSP's intent to require each IRP Candidate Resource Plan to meet the PRM range of 17.8% to 21.0%, or the LOLE of 0.1 days/yr?
		NS Power is required by NPCC to maintain a reliability standard (LOLE) of 0.1days/yr. With NS Power's existing resources, this results in a calculated PRM requirement of 17.8-21%. NS Power will propose a base PRM to be used in the modeling during the Assumptions Development phase of the IRP. As discussed in Section 3.2.1, NS Power anticipates iterating on the required PRM calculation for certain IRP portfolios, which will also be reflected in the Analysis Plan.
2.10	E1	Would it be possible for a feasible Candidate Resource Plan to achieve the LOLE of 0.1 days/yr with a PRM lower than 17.8%?
		Using assumptions consistent with this PRM study, no it is not feasible to achieve an LOLE of 0.1 days/yr with a PRM lower than 17.8%. However, if there were significant changes to the system there may be a resource portfolio which would require a lower PRM to achieve 0.1 days/yr LOLE. As discussed in Section 3.2.1, NS Power anticipates iterating on the required PRM calculation for certain IRP portfolios, which will be detailed in the Analysis Plan.
2.11	E1	Is it correct that a portfolio with less than 17.8% PRM might still achieve a 0.1 days/yr LOLE?
		Yes, a portfolio that is different than the current portfolio assessed by E3 could have a PRM less than 17.8% and still meet the reliability standard.
2.12	Energy Futures Group	What information can E3 provide about the duration, frequency, and seasonality of modeled loss of load events in RECAP? I.e. are the events that tended to contribute to loss of load, but for an adequate reserve margin, "sustained multi-day periods of high loads and corresponding low renewable generation" or were they caused by some other factor and shorter in duration?
		The vast majority of loss of load events in this analysis are short duration in nature given that it is analyzing a system with largely sufficient firm capacity and not one running on only wind and batteries, which is where the nature of the outages would flip to multi-day periods corresponding with low renewable generation. In particular, the average length of a loss of load event in the portfolio that E3 analyzed is 4.7 hours under the higher operating reserve requirement case and lower under the lower operating reserve case. See Table 15 of the Capacity Study report (Attachment 17) for additional reliability statistics. Because NSPI is a winter peaking system, the majority of loss of load events

		occur in the winter months as shown in **Figure A-2** below. These events are not primarily driven by prolonged periods of low renewables but rather by peak load events which are driven by very cold weather.

Figure A-2: NSP Distribution of Reliability Statistics Across Months



2.13	Energy Futures Group	Regarding Table 15, could E3 perform additional scenarios assuming significantly different mixes of EE, DR, storage, renewables, etc.?
		E3 can calculate the statistics provided in Table 15 of the Capacity Study report for any resource portfolio or set of assumptions. As discussed in Section 3.2.1, NSP anticipates the Analysis Plan incorporating a view on potential iteration to test the required PRM for scenario portfolios of interest.

Topic 3: ELCC of Resources (Capacity Study)		
#	**Party**	**Question/Comment & Response**
3.1	Bates White	The E3 study presents Electric Load Carrying Capability (ELCC) estimates for wind, solar, energy storage, and combinations of wind+storage and solar+storage. It is not clear whether this would correspond to five resource addition options for application in the IRP modeling or whether the model would be selecting from three options – wind, solar and storage. NSPI should specify how it is applying the ELCC values for the respective resource options within its IRP modeling.
		The approach on how the ELCC corresponds to resources and resource combinations will depend on the model used for the IRP process. NSP will identify how these candidate resources will be modeled in the Assumptions Development and Analysis Plan phases of the IRP.
3.2	Bates White	NSPI should clarify whether DR will be modeled as a distinct resource alternative with ELCC values, or as a modification to load, or otherwise.
		NSP agrees and will clarify this issue in the Analysis Plan phase of the IRP.
3.3	SBA	The SBA notes that the ELCC analysis should be modified to capture anticipated changes to load shape over time. The ELCC calculations are conducted based on historical load shapes. These load shape assumptions

<table>
<tr><td></td><td></td><td>appear to have a significant impact on ELCC values, particularly for storage and DR resources at higher penetrations. The study should conduct sensitivity analysis assessing the impact of shifting load shapes with electrified heat, transportation, and with greater demand flexibility and dispatchability. This analysis could show a higher (or lower) ELCC for these resources, thus impacting resource planning outcomes.</td></tr>
<tr><td></td><td></td><td>NS Power agrees that different load shapes associated with electrification, DERs, DSM, etc. could impact the ELCC of dispatch limited resources. NS Power anticipates iterating on the Capacity Study for certain IRP Portfolios to provide additional insights into impacts on this reliability criteria. More detail on this approach will be proposed in the Analysis Plan phase of the IRP.</td></tr>
<tr><td>3.4</td><td>AREA</td><td>Please provide the date and hour of peak NSPI system load for each of the last 5 years/winters, what the NSPI load actually was, and what the capacity factor of the wind was (actual production of NSPI/IPP/COMFIT wind divided by nameplate of that same group) during that peak time.</td></tr>
<tr><td></td><td></td><td>Please refer to Figure A-3 for the requested data.

Figure A-3: Historical Capacity Factor of Wind
<table>
<tr><th>Date</th><th>Time</th><th>Peak System Load (MW)</th><th>NSPI Wind Average Capacity Factor</th><th>IPP Wind Average Capacity Factor</th><th>COMFIT Wind Average Capacity Factor</th></tr>
<tr><td>6-Jan-2015</td><td>18:00:00</td><td>2004</td><td>13%</td><td>18%</td><td>NA</td></tr>
<tr><td>2-Feb-2015</td><td>18:00:00</td><td>1973</td><td>19%</td><td>22%</td><td>NA</td></tr>
<tr><td>29-Dec-2015</td><td>18:00:00</td><td>1827</td><td>3%</td><td>3%</td><td>NA</td></tr>
<tr><td>19-Jan-2016</td><td>20:00:00</td><td>1832</td><td>60%</td><td>61%</td><td>55%</td></tr>
<tr><td>15-Feb-2016</td><td>10:00:00</td><td>1883</td><td>47%</td><td>57%</td><td>35%</td></tr>
<tr><td>16-Dec-2016</td><td>18:00:00</td><td>2111</td><td>76%</td><td>47%</td><td>77%</td></tr>
<tr><td>9-Jan-2017</td><td>18:00:00</td><td>1946</td><td>26%</td><td>38%</td><td>48%</td></tr>
<tr><td>10-Feb-2017</td><td>18:00:00</td><td>1888</td><td>49%</td><td>19%</td><td>39%</td></tr>
<tr><td>28-Dec-2017</td><td>18:00:00</td><td>2018</td><td>51%</td><td>88%</td><td>71%</td></tr>
<tr><td>7-Jan-2018</td><td>18:00:00</td><td>2073</td><td>80%</td><td>61%</td><td>47%</td></tr>
<tr><td>3-Feb-2018</td><td>19:00:00</td><td>1999</td><td>33%</td><td>32%</td><td>37%</td></tr>
<tr><td>12-Dec-2018</td><td>18:00:00</td><td>1986</td><td>73%</td><td>20%</td><td>16%</td></tr>
<tr><td>17-Jan-2019</td><td>19:00:00</td><td>2033</td><td>35%</td><td>52%</td><td>85%</td></tr>
<tr><td>27-Feb-2019</td><td>8:00:00</td><td>2060</td><td>85%</td><td>24%</td><td>30%</td></tr>
</table>

This request relates to how wind is assumed to contribute to meeting capacity requirements, as discussed in Section 3.2.2. Effective load carrying capability (ELCC) is the most widely accepted and statistically significant measure of a resource’s contribution to meeting capacity requirements (see, for example, NREL 2008[1]). As computing power increases, this methodology and approach is increasingly being adopted by utilities, commissions, and system operators across the continent to replace older heuristic methods.

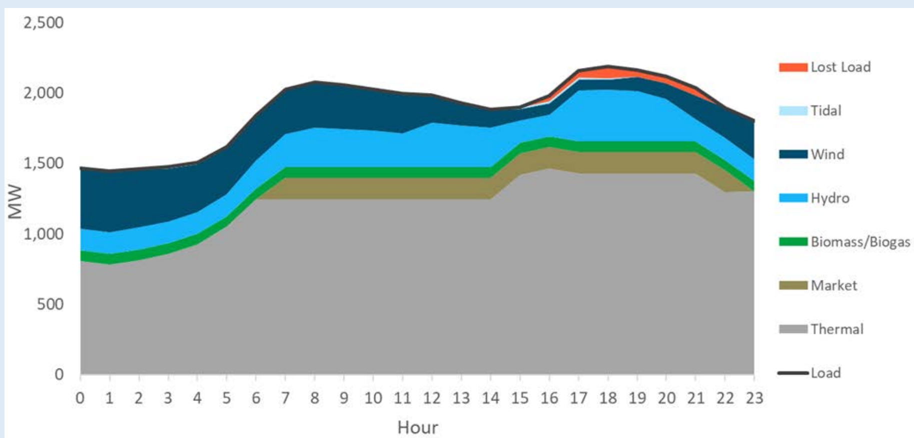
Using a heuristic method such as the 5 peak hours calculation, while potentially intuitive, does not represent a statistically significant representation of capacity value for multiple reasons. First, it does not capture the potential for the “net peak” load hours to shift to a different</td></tr>
</table>

[1] NREL, 2008. “Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation.” NREL/CP-500-43433. Available here: https://www.nrel.gov/docs/fy08osti/43433.pdf

time of day/month/season as more wind is added to the system. This shift reduces the coincidence of wind production and net peak and is a likely outcome at higher penetrations of wind. Second, loss-of-load can occur in many hours besides just the single peak hour, including in the hours directly before and after the peak load hour. The ability of wind to provide capacity value is based on its ability to mitigate loss-of-load in any hour, not just the single peak hour.

To illustrate this point, in **Figure A-4** below we show the system under a simulated loss-of-load event that occurred in the RECAP modeling. This is a dispatch plot for a sample winter day, in which loss-of-load events occurred in late afternoon and early evening (16:00-21:00). The maximum loss-of-load was 81 MW, and the average was 52 MW. This series of loss-of-load hours is mainly driven by high load conditions; however, lower than normal wind generation also plays a role. In particular, while the average wind capacity factor for that day is 41%, during the loss-of-load hours, wind's capacity factor drops to 17%.

Figure A-4: Simulated Loss of Load Event from NSPI Sample Winter Day



In contrast to the heuristic-based approach, we note that the ELCC calculation is based on E3's robust RECAP modeling. RECAP calculates its reliability metrics by simulating the electric system with a specific set of generating resources and loads under a wide variety of weather years, renewable generation years, and stochastic forced outages of electric generation resources and imports on transmission. Correlations enforced within the model capture linkage among load, weather, and renewable generation conditions. Time-sequential simulation tracks the state of charge and energy availability for dispatch-limited resources such as wind, hydro, energy storage, and demand response. By simulating the system thousands of times with different combinations of these factors, RECAP provides robust, stochastic estimation of reliability metrics. In the PRM study, wind's effective average and marginal ELCC is shown in Figures 28-29 (Attachment 17 pages 58-59).

3.5	E1	Please describe assumptions that were used in DR dispatch within RECAP.
		Please refer to Section 3.4.4 of the Capacity Study report (Attachment 17). As described, DR for the purposes of the PRM study is defined along two characteristic dimensions: number of annual calls and duration of each call. The system dispatches DR, subject to annual calls and call duration, when the system would otherwise experience a loss of load event. Three illustrative demand response programs are modeled and presented in the E3 PRM study to demonstrate the ELCC of these resources.
3.6	E1	Does NSP consider it to be an economic decision to dispatch all available resources, including the highest cost fuel dispatch, before employing DR?
		No. As discussed, the RECAP model used to evaluate the ELCC of DR does not consider the economics of dispatch – please also refer to response 3.7 below. As discussed in Section 3, the actual forecast dispatch of DR in various scenarios will be developed using the IRP economic modeling.
3.7	E1	Please describe the methodology used to dispatch within RECAP and why DR is used as a last resort.
		Like all resources in RECAP, DR is dispatched for the purposes of reliability, not economics. This approach is consistent with the system operator having perfect foresight and maximizing the reliability of the system. DR is dispatched as a resource of last resort because this maximizes the reliability of the system. In other words, RECAP will not turn down a power plant and dispatch DR in its place. While DR may be dispatched in this way in practice for economic or environmental reasons, if the DR program is constrained by the number of times that it can be called, then using a call when a power plant is available to produce energy reduces the availability of DR for the future when it may be needed to avoid loss of load. From a reliability perspective, the system operator maximizes reliability by only using DR when it is needed to avoid loss of load. In practice, if a system operator has very good foresight and knows that it will not need all of the DR calls for reliability, then it could dispatch DR for economics or environmental reasons (i.e., not as a last resort). However, this would not contribute any ELCC or reliability value to the system which is what the PRM study is trying to measure. As discussed in Section 3, the IRP modeling will take into account the economics of system dispatch (e.g. a DR program may be called upon rather than a power plant for economic purposes).
3.8	E1	Why were solar profiles limited to 2008-2010?
		These are the only years for which solar data was available over a wide geographical area for a wide variety of future solar installation configurations. The National Solar Radiation Database only contains data for 2008-2010 and E3 needed to use a dataset that had solar radiation data for areas beyond just where solar is installed today in Nova Scotia and for configurations of solar such as single-axis tracking that may not yet be installed at many of Nova Scotia's existing solar locations.

3.9	E1	Is it assumed that no DR options exist for dispatch in 2020 as per slide 14 dispatchable resources?
		Yes. NS Power does not currently have dispatchable DR options in its forecast for next year.
3.10	E1	Is Maritime Link/Muskrat Falls base block energy and/or other energy purchases across the Maritime Link considered to be dispatchable in the RECAP model?
		As described in Section 3.3.5 of the Capacity study (Attachment 17), RECAP considers 153 MW of dispatchable capacity over the Maritime Link with an additional 2% DAFOR. For the purposes of RECAP, “dispatchable” is synonymous with “available”. RECAP measures the total availability of resources relative to the total demand of the system and does not account for factors such as ramp rate, up/down times, etc., which would be captured in a more detailed production cost model.
3.11	E1	Is Wreck Cove assumed to be available to produce 500-1100 MWh every day of the year in the model? Or did E3 consider a seasonal shape applied based on storage and historical hydrology?
		As described in Section 3.3.2 of the Capacity Study (Attachment 17), the daily MWh hydro generation for Wreck Cove varies by month. 500 MWh/day is used in June. 800 MWh/day is used in April and July-November. 1,100 MWh/day is used in December-March. These values reflect the seasonality of the resource and historical hydrology data. For each day within these months, the corresponding MWh value above is used.
3.12	E1	Please explain the definition of “Effective Capacity” and why in many cases it matched with nameplate capacity (Slide 21). Effective capacity changes on slide 23. Please explain.
		The term “Effective Capacity” on Slide 21 of the Capacity Study summary presentation (Attachment 5 page 31) refers to the contribution of various resources toward meeting the total planning requirements (i.e., firm net peak load plus the target PRM). As described in Section 1.3 of the Capacity Study (Attachment 17), dispatchable resources (coal, oil, natural gas, biogas, biomass, and Run-of-River hydro resources) are counted by convention using their net dependable capacity while dispatch-limited resources (wind, solar, tidal) are counted using effective load carrying capability (ELCC). As discussed in Section 1.4 of the Capacity Study (Attachment 17) and pages 14 & 32 of the summary presentation (Attachment 5), ELCC measures the ability of non-firm resources such as wind, solar, storage, hydro, and demand response to contribute to the PRM while still maintaining an equivalent level of system reliability. Equivalently, ELCC is the quantity of “perfect capacity” that could be replaced or avoided with renewables or storage while providing equivalent system reliability. On page 33 of Attachment 5, we report an example ELCC for all resource types (including dispatchable resources). This illustrative comparison is provided given that despite the industry standard convention to count dispatchable resources at their nameplate capacity for PRM calculations, these resources do experience forced outages that mean they are less

		reliable than "perfect" capacity that is always available with no forced outages. The calculated ELCC for all resource types accounts for the forced outages of thermal units and other interactive effects such as the lumpiness of units and the resulting impact on system reliability.
3.13	E1	How does RECAP account for the need to "recharge" energy storage capacity and potential loss of availability?
		RECAP explicitly tracks the hourly availability of the system to charge storage by accounting for how much excess generation there is above and beyond what is needed to serve load. Only total available generation (thermal + hydro + renewables + imports) minus total load can be used in any hour to re-charge storage.
3.14	E1	Based on changes to weather patterns in recent decades, how is using prediction of weather going back to 1950 a reliable assumption for weather calibration in the RECAP model? Renewable generation predictive modelling will likely have a wide array of outcomes based on more recent weather trends vs tracing back to 1950.
		In E3's experience, using a larger number of historical weather years more accurately captures the frequency of extreme weather events and puts these temperature events into context more accurately. It is true that climate change impacts could theoretically have a marginal impact that renders historical data slightly inaccurate. However, the approach taken in the Capacity Study, which utilizes a longer panel of available weather information, yields a more robust answer than one that just considers a smaller number of years.
3.15	E1	Please explain why ELCC (marginal ELCC) becomes zero after only 100MW of DR are on the system (slide 42 and 43) and please explain why ELCC changes between the 2 charts when DR capacity remains constant.
		Slides 42-43 show three different illustrative DR programs with different characteristics in terms of the number of annual calls and the duration of each call. Please refer to page 71-72 of the Capacity Study report (Attachment 17) that documents the number of calls and duration of each call per program. Programs with more calls and longer duration have higher ELCC and a marginal ELCC that diminishes more slowly. If a resource has a marginal ELCC of zero at a particular penetration, this means that the existing DR on the system has been dispatched during the peak hours and flattened net load such that the required duration or number of calls required to further reduce peak is larger than what that DR program can provide.
3.16	E1	How is the ELCC diversity benefit allocated between resources? To which resources is it allocated? What are the implications of different methods of allocation?
		This Capacity Study does not allocate diversity value but rather calculates the aggregate diversity benefit for different combinations of resources. All individual ELCC results are shown on a stand-alone basis assuming no other incremental dispatch-limited resources on the system. From an IRP perspective, the diversity value will need to be accounted for through either an allocation process or through a general diversity adjustment. Please refer to response 3.1.

3.17	E1	Does diversity in the types of demand response programs produce a larger ELCC diversity benefit than a single demand response program?
		DR programs with more annual calls or longer call durations will have higher ELCC across the board. However, it may be more economic to create a portfolio of DR programs with more or less calls since a program with fewer calls may be cheaper from the utility's perspective. This is an economic question that would be addressed in the IRP modeling.
3.18	Energy Futures Group	What process did E3 undertake to determine whether temperature was a significant driver of renewable production?
		Determining a relationship between these two specific factors is not an explicit step in the analysis as the model inherently captures this along with many other factors in determining both the reliability of the system and the ELCC of many different resources. However, E3 did analyze the correlation between wind and load as a side analysis, with load being a proxy for low temperatures. E3 found very low correlation with wind and high load, meaning that there was no systematic bias toward wind being higher or lower during high load events. The model captures this relationship inherently in calculating the ELCC of wind.
3.19	Energy Futures Group	In RECAP, do the renewable production draws result in convergence to a particular capacity factor over a given period, e.g, a year?
		Yes, over a year, the capacity factor of wind and other renewables will converge to the capacity factor for the specific number of years that are simulated or used in the actual data. For example, the weighted average capacity factor of actual NSPI wind from 2011-2018 is 35.2% and over a large number of years, the E3 simulations will reflect a nearly identical average capacity factor
3.20	AREA	We are reserving our comments on the ELCC for renewables until we receive the requested data.
		Please refer to Attachment A-1 which provides hourly data on the distribution of the simulated wind profiles compared to actual production data, as discussed. Please also refer to response 3.19.

Topic 4: New Bulk Grid Supply Options (Supply Options Study)		
#	**Party**	**Question/Comment & Response**
4.1	Bates White	We requested that E3 provide a detailed breakdown of its cost estimates for each new technology that were presented generally on slides 8 and 9 (capital cost assumptions & Pro-Forma Financial Model) of the study.
		Details of E3's cost assumptions are available on Slides 18 through 75 by technology. E3's pro forma model incorporates capital costs, fixed and variable operations and maintenance costs, fuel costs, as well as key financial and operational assumptions to calculate levelized cost of energy or levelized fixed costs for various resources. Each resource section of the Resource Options Study results contains the relevant data for each of these inputs, including capital costs, operating assumptions (such as capacity factor), variable O&M, fixed O&M, financing lifetime, cost of debt and equity, and other key assumptions.

4.2	Bates White	NSPI should reconcile the costs associated with "maintaining generating capacity, independent of operations" provided by E3 for new resources, and NSPI's own sustaining capital cost assumptions for its existing asset fleet.
		Sustaining capital costs for new resources in E3's Supply Options Study are embedded in the Fixed O&M estimate which have been derived from various sources (e.g. Lazard, NREL, public IRP's, etc.). This levelized methodology is consistent with "big picture" planning studies. In contrast, NS Power forecasts sustaining capital estimates for its existing assets using a detailed, bottom up approach based on projected utilization factor, in addition to forecasted Fixed O&M. Since existing resource retirements will be a critical consideration in this IRP, the non-levelized nature of sustaining capital forecasts (vs the annual Fixed O&M estimates) will be an important factor in the optimization model methodology for retirement decisions. NS Power anticipates utilizing both methods (i.e. embedded in FO&M for new resources and segregated FO&M and sustaining capital for existing resources). FO&M for existing resources will be provided in the Assumptions Development phase. The Analysis Plan phases of the IRP will define how these assumptions will be reflected in the modeling.
4.3	Bates White	In the IRP, it will be important to ensure that (a) smaller units or configurations be considered which, though they may have a higher $/kW cost, could address the "lumpiness" issue associated with the PRM, and (b) larger units/configurations be considered, and done so in a way that captures economies of scale.
		NS Power anticipates utilizing a $/kW as the input assumption for capital costs of new resources, as per E3's Resource Option Study and consistent with long-term planning practices. While larger units/configurations may provide economies of scale, due to NERC/NPCC requirements, larger units could significantly increase NS Power's operating and/or planning reserve requirements. The costs estimated in the Resource Option Study are based on appropriately scaled units, representative of NS Power's relatively small size and the corresponding impacts to reliability planning. The number of resources (including varied capacity/configuration options and potential economies of scale), will be determined during the Assumptions Development and Analysis Plan phases of the IRP.
4.4	Bates White	E3 should explain the currency conversion assumptions it used. For example, E3 claims that the "NREL 2018 ATB" cost for a 50 MW CT – Frame is $1,226 (CAD); however, this would suggest an exchange rate of at least 1.39 and as high as 1.42.
		E3 applies an exchange rate of 1.32 from US$ to CAN$ both in 2019 dollars. The overnight capital cost for CT – Frame ($864/kW) referenced in the comment is in 2016 US$, so it needs to be converted to 2019 US$ before applying the exchange rate above. The all-in-one conversion rate from 2016 US$ to 2019 CAN$ (based on inflation of 6% from 2016 to 2019 and exchange rate of 1.32) is about 1.40.
4.5	Bates White	NSPI should ensure that E3's data is up to date. The 2018 NREL STB Study is based on data as old as 2014. We note that multiple stakeholders raised concerns with the onshore wind assumptions put forth by E3 as inconsistent

		with recent provincial wind prices. We would also point to examples such as Maxim Power's recently-announced 204 MW simple cycle gas turbine, which has a total capital cost of $706/kW (CAD) (without financing costs).
		As described in the Resource Options Study presentation, E3 considered multiple data sources, including both standardized industry cost estimates as well as other regional IRP assumptions. The most recent vintages of cost information available at the time of the study were utilized. The E3 capital cost estimates for onshore wind are not only based on NREL 2018 ATB, but were also informed by the 2017 New Brunswick IRP, a recent WECC survey of projects in the Western US, and the most recent information from NSPI's internal engineering team (Slide 21). E3 believes this is the best estimate based on the current market in North America plus local adjustment for Nova Scotia. Similarly, multiple sources were considered for combustion turbines, using industry standard data sources and regional IRPs. Please refer to response 4.13, which clarifies the proposed onshore wind prices. E3 notes that the 2019 NREL ATB was released after the Nova Scotia Power Resource Options study was completed, but features nearly identical capital costs for both onshore wind and gas CTs as the 2018 NREL ATB.
4.6	Bates White	E3's capital cost estimate (at slide 48) for 4-hour duration battery storage may conflict with its own recommendations elsewhere. On slide 48, E3 recommends at $2,325/kW capital cost; however, in its 2018 WECC Survey, it recommends $1,500 USD/kW for standalone 4-hour energy storage, which at a conversation of 1.33 USD/CAD, would equal $1,995 CAD/KW. The reason for this deviation is not provided.
		Please refer to response 4.8.
4.7	Bates White	NSPI should consider modeling longer duration storage options (beyond 4 hours).
		NS Power anticipates modeling several different duration storage options. The types of storage resources and their respective duration and capacity will be developed in the Assumptions Development Phase of the IRP.
4.8	Bates White	Similarly, E3 should provide further support for its estimates of future battery storage costs, which E3 acknowledged are based on Lazard estimates (slide 49).
		E3's cost estimates are informed by the 2019 WECC Survey and Lazard 4.0, and were also informed by insights provided by NSPI's internal engineering team. Lazard 4.0 provides a range of current costs informed by energy storage developers. Based on the sources consulted for this study, E3 recommended a value on the higher end of the Lazard range, considering local cost drivers, including limited local energy storage development experience to date. (Note: the 2019 WECC Cost Survey selected only one point within the Lazard 4.0 range.) Future battery storage costs follow the percent cost reduction trajectory based on Lazard 4.0 (Slide 49). Given the large uncertainty in current costs, it will be useful to consider various scenarios in the IRP process. Cost sensitivities/scenarios will be developed in

		consultation with stakeholders through the Assumptions phase of the IRP.
4.9	Bates White	The IRP should include pumped storage options (slide 57) that are outside Nova Scotia. As E3 notes, pumped storage costs can vary considerably and are highly site-specific.
		NS Power in unaware of non-domestic pumped hydro facilitates in proximity to NS with well-defined cost metrics. The Company welcomes submissions from stakeholders with cost supports for this type of project to consider for inclusions in the Assumptions Development phase.
4.10	Bates White	It is not clear why E3 limited its analysis of coal-to-gas conversions to a few specific units (slide 61). A more thorough analysis should be required for the IRP.
		The Trenton and Point Tupper facilities are the only coal plants in Nova Scotia that could utilize existing natural gas pipeline infrastructure for gas conversion; therefore, NSP believes they are the only units that should be examined as plausible candidates for conversion.
4.11	Bates White	E3 noted during the August 7 stakeholder meeting that they had not developed any estimates for the cost of incremental firm natural gas pipeline capacity for the IRP. This is a critical assumption that should be discussed in advance of the IRP.
		NS Power concurs that this is a critical assumption. This will be developed in consultation with stakeholders in the Assumptions phase of the IRP.
4.12	AREA	With this objective in mind, we request that the IRP consider project financing structures beyond traditional NSPI ownership. Based on our direct experience, capital is available at rates lower than typically associated with NSPI ownership and this will lead to reduced renewable energy generation and integration costs.
		NS Power will consider this feedback in the development of its Analysis Plan and Assumptions for the IRP.
4.13	Envigour	Please expand upon the rationale given at the session on August 8, 2019 with respect to the wind capex numbers being relatively constant over the past ~ 8 years (~$2 million CAD) while PPA prices in cost per kwh in Nova Scotia have declined by a third to nearly 2/3 over the same period of time. [as reference for prices 8 years ago see price assumptions for capex COMFIT large wind tariff proceedings for 13.5 cents per kwh and for price assumptions 5-6 years ago see rate for South Canoe ~ 7.5 cents per kwh and as reference for prices today please reference any information you have on Emera's RFP responses for the Atlantic Link project believed to be in the range of 5 – 6 cents per kwh]
		PPA prices are not entirely a function of capital costs as turbine sizes have increased and technology has improved, which has allowed for higher capacity factors from the same capital cost investment, indicating that PPA prices are not exactly proportional to capital costs over time. As shown on slide 26 of E3's presentation, onshore wind projects online in 2020 are projected to be $47-55/MWh, equivalent to 4.7-5.5 cents/kWh, which is consistent with the RFP response referenced (of 5-6 cents/kWh). This cost is

		forecasted to decline over the period. Additionally, slide 23 provides sensitivities for more aggressive capital cost declines which would further reduce the future $/MWh of wind, which can be tested in the modeling phase of the IRP. NS Power will discuss modeling capital cost sensitivities with stakeholders in the Analysis Plan and Assumptions Development phases.
4.14	AREA	Also based on our experience, the cost to build more wind energy in Nova Scotia is much less than that stated in the provided reports. NSPI affiliates should be well versed in such costs, having conducted an RFP for renewables for the Atlantic Link a few years ago. Costs have dropped since that time. Furthermore, existing sites in Nova Scotia have expansion potential, enabling even lower costs to build and operate incremental wind energy assets. Installed costs should be less than $1.5 million CDN per MW with a net capacity factor in excess of 40%.
		Please refer to response 4.13. NS Power will also consider this feedback in its development of scenarios and/or sensitivities through the Assumptions and Analysis Plan Development phases.
4.15	E1	Why is demand response not considered to be a viable resource option?
		DR is considered to be a viable resource option. E3's Supply Option Study considered only supply side options at the bulk grid scale. Demand Side Options, including DSM and specifically DR will be assessed in the upcoming IRP; the details of these options will be outlined in the Assumptions Development phase.
4.16	E1	Please confirm that 2030 capital costs are discounted to $2019
		Yes, all 2030 capital costs are in 2019$ (CAD).
4.17	Energy Futures Group	Could E3 provide the pro forma model that it developed for Nova Scotia Power?
		Please refer to response 4.1.
4.18	Energy Futures Group	What factors make the estimated cost of pumped hydro, "informed by NSPI engineering estimates", so much lower than the other estimates cited by E3?
		As per E3's study, "Pumped storage costs are highly site-specific and can vary considerably based on the characteristics of the site". The cost estimate utilized, excluding transmission integration costs, is based on a consulting engineering firm estimate (2012) for a specific site in Nova Scotia (Wreck Cove).
4.19	Energy Futures Group	What are the assumed operating costs for coal and biomass co-firing?
		All operating costs will be provided in the Assumptions Development Phase.

Topic 5: Sustaining Capital (Supply Options Study)		
#	**Party**	**Question/Comment & Response**
5.1	Bates White	Please explain the components of each year's sustaining capital cost.
		As discussed in Section 3.3.2, the annual 10 Year System Outlook Report

<table>
<tr><td></td><td></td><td>outlines the process NSP uses to develop the sustaining capital forecast for the thermal fleet in (the most recent 2019 System Outlook provides this in Section 3). The forecast is developed using the understood condition of the unit assets and the unit's expected utilization, as forecasted each year.

The sustaining capital cost is forecasted by asset class. Figure A-5 below illustrate the components considered for thermal and hydro units. If assumptions change between years, which drive changes in the expected energy production, starts/cycles, or operating hours of the units, the utilization forecasts can drive changes in the sustaining capital requirements for each asset class, as their investment requirements are driven by their use and condition.

Figure A-5: Asset Classes for Sustaining Capital Forecasts

<table>
<tr><th>Thermal Asset Classes</th><th>Hydro Asset Classes</th></tr>
<tr><td>Boiler</td><td>Balance of Plants & Tools/Equipment</td></tr>
<tr><td>Combustion Turbines</td><td>Control Valve</td></tr>
<tr><td>Cooling Water</td><td>Crane</td></tr>
<tr><td>Environmental & Emissions</td><td>Dams and Water Impounding</td></tr>
<tr><td>Fuel Systems</td><td>Electrics</td></tr>
<tr><td>Feedwater</td><td>Generator Rotor</td></tr>
<tr><td>Generator</td><td>Generator Stator</td></tr>
<tr><td>Instrumentation & Electrical</td><td>Governor</td></tr>
<tr><td>LM 6000 Engines</td><td>Headgate Trash Rack</td></tr>
<tr><td>Routine</td><td>Instrumentation & Controls</td></tr>
<tr><td>Turbines</td><td>Penstocks</td></tr>
<tr><td>Other</td><td>Structures (Separate from Dam)</td></tr>
<tr><td></td><td>Surgetanks</td></tr>
<tr><td></td><td>Tailrace</td></tr>
<tr><td></td><td>Turbine & Components</td></tr>
</table>
</td></tr>
<tr><td>5.2</td><td>Bates White</td><td>Regarding the CTs: NSPI projects $23.4 million in sustaining capital costs for the CTs the for three-year period (2020-2022). The next six years, the total sustaining capital is expected to be less than that—just $22.6 million. Please explain the assumptions behind this result.</td></tr>
<tr><td></td><td></td><td>The 10 year plan shows larger investment in the first three year due to the forecasted spend on the ongoing life extension of the Pratt and Whitney Fleet. Once the life extension work is completed, the required sustaining capital is forecasted to decrease to levels for non-life extension annual requirements. NS Power plans to evaluate the economics of the combustion turbine fleet in, as will be detailed in the Analysis Plan phase.</td></tr>
<tr><td>5.3</td><td>Bates White</td><td>Regarding the hydro assets: NSPI projects $131.7 million in spending over the next four years (2020-2023) but just $50.2 million in spending over the following five years (2024-2029). Please explain the assumptions behind this</td></tr>
</table>

		result.
		This is due to the Wreck Cove Life Extension Modernization project which is forecast to occur in the next 4 years. This standalone capital item drives a higher cost in the early years, and will be filed as a separate Application for approval with the UARB.
5.4	Bates White	Regarding the hydro assets: Please explain any result in which an asset is expected to have “0.0” in sustaining capital.
		Results with a “0.0” indicate that there are no major refurbishment on significant asset classes forecasted for that unit in that year. There is a Balance of Plant (BOP) of 2.5 million per year forecasted for all hydro units (approximately $50,000 per unit). While this BOP value is not forecasted in detail on a per-unit basis, it is applied evenly across all units in the sustaining capital forecast (due to rounding this did not show in the hydro capital table). Please refer to Attachment A-2 for an update including the BOP value.
5.5	Bates White	Regarding the thermal assets: Please explain the components of “Unit 0” costs.
		Unit 0 refers to common plant; for stations with more than one unit, this category is used to reflect common assets and/or systems shared by multiple units (e.g. fuel handling, ash management, etc.).
5.6	Bates White	How do these forecasts compare to previous forecasts of sustaining capital for each individual year 2020 through 2029, inclusive?
		The sustaining capital investment forecast is developed using the expected unit utilization based on the assumptions at that time; as these assumptions change year over year, changes in the utilization forecasts drive changes in the sustaining capital requirements. **Figure A-6** below shows the projected unit utilization factors from the annual 10 Year System Outlook Report.

Figure A-6: 2019 10 Year System Outlook Forecast Utilization Factors

Unit	Utilization Factor (2020-2024)	Utilization Factor (2025-2029)
LIN-1	High	Med
LIN-2	Med/Low	Off
LIN-3	High	High
LIN-4	High	High
PHB-1	High	High
POA-1	High	High
POT-2	High	Medium
TRE-5	Low	Low
TRE-6	Medium	Medium
TUC-1	Low	Ultra Low
TUC-2	Low	Low
TUC-3	Medium	Medium
TUC-4	High	High
TUC-5	High	High
TUC-6	High	High

		Major changes in the asset management plan from the previous forecasts include: • Increased cycling (output ramping or two-shifting) of the thermal fleet can sustain the unit utilization factors even as the capacity factors decline. For example, a unit that is heavily cycled can require more sustaining investment than a base loaded machine. • Lower Utilization forecasts for Trenton Unit #5 have dropped the sustaining capital by approximately 29 percent over the period. • Higher Utilization of Lingan Unit #1 has driven the Turbine major turbine refurbishment interval into 2021. • If you look at the period from 2019 -2027 across the previous forecast it shows an increase of 53.2 MM (9 percent) over the 2018 10YSO. This is due to the sustained utilization of the thermal fleet as outlined in the 2019 10YSO. • **Figure A-7** below provides a summary comparison of the previous 10 Year System Outlook sustaining capital forecasts as well as the "high" case tested in the Generation Utilization & Optimization proceeding

Figure A-7: Thermal Sustaining Capital Forecast Comparison ($Millions)

Year	2019 System Outlook	2018 System Outlook	2017 System Outlook	GUO (High Case)
2018			$61.9	$77.4
2019	$73.0	$73.0	$65.2	$81.5
2020	$68.0	$62.4	$55.8	$69.8
2021	$86.5	$80.8	$60.0	$75.1
2022	$74.8	$67.7	$89.7	$112.1
2023	$75.9	$62.7	$57.7	$72.1
2024	$67.7	$60.5	$63.9	$79.9
2025	$69.2	$57.2	$50.6	$63.2
2026	$53.7	$60.6	$45.4	$56.8
2027	$62.5	$53.3	$51.4	$64.3
2028	$97.6			
2029	$59.2			
Total (2019-2027)	$631.4	$578.2	$539.8	$674.7

5.7	Bates White	How do these forecasts compare to actual sustaining capital costs over the past ten years for each asset? Would unplanned maintenance costs be captured in actual sustaining capital costs?
		Please refer to Attachment A-3. Yes, unplanned refurbishment costs are captured in actual sustaining capital costs.
5.8	Bates White	It appears that NSPI's sustaining capital costs include only those costs/investments related to planned refurbishments. (NSPI has noted to date that such costs included the expected refurbishment costs, AFUDC, and "administrative overhead," though it is unclear to us how these numbers are derived, despite having reviewed the most recent ACE filing and 10-year

		system outlook study.)
		NS Power's methodology for projecting sustaining capital utilizes the costs of previous major refurbishments, which includes AFUDC and Administrative Overhead (AO).
5.9	Bates White	NSPI's sustaining capital costs do not seem to include all avoidable costs, i.e., those costs that would be avoided if the plant were mothballed or shut down. NSPI's sustaining capital estimates will have to be consistent with E3's defined costs associated with "maintaining generating capacity, independent of operations" provided by E3 for new resources.
		As discussed in response 4.2 above, other fixed costs above sustaining capital will be modeled in the IRP for existing resources. The details of these costs will be provided in the Assumptions Development phase of the IRP.
5.10	Bates White	Capital investments by NSPI appear to be underway (or recently finished) on numerous assets in its fleet, including the CTs and Wreck Cove. It is important that these costs – unless they are both approved by the Board and already expended – be considered in the IRP process – i.e., they should be treated as potentially avoidable.
		The IRP will not re-evaluate projects that have been approved by the Board. Section 35 of the Public Utilities Act, requires pre-approval of capital projects over a certain dollar value. The NSUARB reviews applications for approval through its established capital review process and if it determines the project is required for the provision of electricity service, it is approved. The IRP is not a replacement for the NSUARB's well established capital project vetting and approval process; it is not an application for approval of specific NSPI initiatives, nor is it a commitment by NSPI to undertake specific initiatives. Correspondingly, the IRP is not a process to second guess determinations made by the NSUARB that specific projects are justified and to be pursued.
5.11	Energy Futures Group	Will the "sustaining capital" investments in the Addendum to the study be modeled in Plexos?
		Yes, with scenarios/sensitivities that test higher ranges of spending, as discussed in Section 3.3.2.

Topic 6: Renewables Integration Stability Study		
#	**Party**	**Question/Comment**
6.1	Bates White	How has PSC addressed the impact of the Maritime Link, including additional transfers from NLH for sales into New Brunswick/ISO New England? Did PSC modeling consider any contractual transmission priority over the Maritime Link for firm NLH sales in the ISO New England market with respect to transmission for NSPI Supplemental Energy?
		For the purposes of the transient stability model, PSC incorporated the impact of the Maritime Link by having Case 3 set up at the maximum levels for: 1) the Maritime Link transfer from NL to NS; 2) the AC tie transfer from NS to NB; and 3) the AC tie transfer from NB to NE. As noted in Section 3.4, this type of model would not consider contractual issues as described in the question (the contracts would not have an impact on the system stability parameters, which are based on line flows).
6.2	Bates White	How has PSC addressed and modeled NSPI's imports over the Maritime Link?

		Please distinguish between the NS Block energy and Supplemental Energy.
		All energy supplies from the Maritime Link, including all energy blocks and potential excess energy up to the maximum flow, are reflected in Cases 2, 3, and 4 with the maximum transfer from NL to NS. As discussed in Section 3.4, the specifics of each block or contract do not impact transient stability studies.
6.3	Bates White	How has PSC addressed the availability of transmission on the Maritime Link for NSPI to import Supplemental Energy? Has PSC modeled all firm commitments on the Maritime Link, other than those enjoyed by NSPI? And how has PSC modeled any non-NSPI firm transmission commitments on the NSPI system?
		Please refer to the previous responses (#6.1and #6.2) and Section 3.4.
6.4	Bates White	Would the additional 345 kV line to New Brunswick have any impact on the expected impact of the Maritime Link operating in full with Muskrat Falls also operating in full?
		With a second tieline to New Brunswick, there could be changes to the requirements from Maritime Link to cover the loss of the existing NB tieline (e.g. runback from the Maritime Link may not be required).
6.5	Bates White	How did PSC decide upon/develop the scenarios discussed in the “Study Results” section at pages 5-6?
		In order to refine a reasonable scope to inform IRP modeling effectively, the limited number of cases selected were based on their representation of the most stressed transfer levels, which would illustrate the most critical system states to examine for stability purposes. These would be the most likely cases to identify system issues in order to define the appropriate solutions (e.g. integration costs) to be used in IRP modeling for new resources.
6.6	Bates White	Please confirm that PSC did not consider any wind penetration scenarios beyond 1,000 MW. If confirmed, please explain why additional wind penetration was not considered.
		As discussed at the Stakeholder Engagement Session on August 27, 2019, PSC did test beyond 1000 MW of wind. At the 1050 MW wind level (with the second tieline and/or battery and synchronous condenser solutions that enabled the 1000 MW cases to obtain stable results), Case 3 resulted in an unstable system - see *Table 5-6, Summary of Transient Stability Simulation Results, Base Cases with Second 345 kV Tie*. As discussed with stakeholders and in Section 3.4, NSP will work to determine what additional potential solutions would be required to maintain system stability for wind penetration levels above 1000 MW and will bring these forward for discussion with stakeholders through the Assumptions Development phase.
6.7	Bates White	Were there any results of the PSC study that would imply new or changed reliability constraints on the NSPI system?
		No. The constraints for the existing system were confirmed by PSC’s work. However, the study provided guidance on reliability constraints and other tools to monitor and/or consider as the renewables penetration increases (e.g. modifications to the grid code).
6.8	Bates White	Could the lack of consideration of synthetic inertia potential be understating the potential benefits of energy storage? (See page 8.)
		Synchronous inertia, which is produced by conventional generators, is

		provided directly to the grid by physically connected devices (with no power electronics separating the electrical circuit). The effects on the electrical grid have a direct impact on that mechanical energy of such machines and vice versa. Thus, when a system frequency event occurs, the machine will naturally react to the frequency changes, resulting in an "instantaneous" mechanical system reaction. For synthetic (non-synchronous) inertia, on the other hand, this direct electromagnetic connection between the grid and the device does not exist. Instead power electronics are used to "mimic" inertia on the grid. The largest obstacle for synthetic inertia is its response time (the device must physically detect and then respond to an event, while conventional generators do this instantaneously). It is unclear what level of synthetic inertia can be used to replace synchronous inertia. NSP is currently investigating synthetic inertia in wind farms and the possibility of grid code revision to include such services for future wind farms and/or potential for retrofit. As discussed in Section 3.3, understanding the provision of essential grid/reliability services (including inertia, whether synchronous or synthetic), is an issue we would like to examine further throughout the IRP. NS Power expects the potential benefits of energy storage, including the provision of services such as synthetic inertia, to be discussed through the IRP modeling work.
6.9	Bates White	Did the PSC study the feasibility of Virtual Synchronous Generators (VSG), consisting of inverters with virtual inertia control algorithms with or without battery storage, in lieu of synchronous condensers, to accommodate higher penetration of wind?
		No. PSC considered battery storage as a form of virtual inertia. This type of solution could be a substitute for the proposed storage and synchronous condenser combination. NS Power will consider this in its Assumptions development.
6.10	Bates White	The study does not establish any volume limit to additional wind resources on the NSPI system. Rather the study recommends an expanded analysis to explore this question.
		The purpose of the PSC Study was to confirm that the NS system was stable at the current penetration level of wind, and to establish requirements for increased levels of wind. The study confirmed that the existing 600 MW of wind can be accommodated by the system as long as a minimum number of thermal generators remain online. The study also indicated that up to 1000 MW of wind could be integrated with a 2nd tieline to NB and/or a battery and synchronous condenser solution. This represents the first "next step" in renewables integration in Nova Scotia, and a significant finding for establishing the IRP assumptions. Since system stability will change depending on the resource mix on the system, it is impossible to define specific volume limits for the NSPI system (given it is likely the IRP will evaluate various scenarios with different resource combinations). As discussed in Section 3.4 and response 6.6, the potential solutions to accommodate additional volumes of wind above 1000

		MW will be proposed in the Assumptions Development phase.
6.11	Bates White	While the study finds that addition of a second 345kV tie to New Brunswick (Onslow to Salisbury) would enhance the ability of the system to accommodate at least 400MW of additional wind resources, the study does not conclude either that the additional tie is required to accommodate more wind, or that 400MW represents a maximum incremental addition of wind.
		NSP does not believe the study indicates that 400 MW is the maximum incremental addition of wind – please refer to response 6.6 above. The study indicates that there are multiple solutions to accommodate wind above current levels, including the second tieline to New Brunswick and batteries with synchronous condensers.
6.12	Bates White	It does not appear that the study considered synthetic inertia potential via Virtual Synchronous Generators (consisting of inverters with virtual inertia control algorithms), in place of synchronous condensers, to accommodate higher penetration of wind. While rotating inertial mass plays an important role in supporting system stability, there is increasing recognition that synthetic alternatives can be effective and cost-efficient. Any expanded analysis should evaluate such alternatives.
		Please refer to responses 6.8 and 6.9 above.
6.13	Bates White	The study asserts that "[I]introducing larger volumes of power electronic devices into the system has known adverse effects with regards to, for example, harmonic distortion levels on the system." An expended study should fully address the factual basis for this in the context of the NSPI system, whether new synthetic inertia methods mitigate the significance of this issue, and the relevance to greater wind integration and the IRP more broadly.
		As discussed in the stakeholder engagement sessions, understanding the provision of essential grid/reliability services, and identifying further study that should be undertaken to address potential operational issues, is an issue we would like to examine and discuss throughout the IRP.
6.14	Bates White	The study notes that the implications of potential grid code modifications were not addressed. This should be incorporated in any expanded analysis.
		Please refer to response 6.13.
6.15	SBA	Are the challenges associated with additional inverter-based generation dependent upon the resource type? Would the results have been the same if solar was added instead of wind?
		As referenced in the report, the generic conclusions would apply to other power electronic interfaced generation resources such as solar.
6.16	SBA	Re: Table 4-1 (study cases), how did NSPI select these assumptions? For example, why was the NL import level set at 475 MW?
		Please refer to response 6.5. The ML capability is 500 MW sending, but after accounting for losses, the net maximum receiving is 475 MW.
6.17	SBA	Please explain in more detail the modifications to Case 01 (pp. 39-40). Would this still be considered a "Light Load" case? Were any other load levels between 678 MW and 893 MW tested?
		The original Case 1 was developed with no thermal unit online in Nova Scotia for PSC to determine the minimum number of thermal units that must be

		online in Nova Scotia for the system to be stable (PSC subsequently confirmed that 3 thermal units must be online). In order to accommodate turning on the 3 thermal units in the Case, PSC had 2 options: 1) Curtail the wind or 2) to increase the system load. PSC opted to increase the system load from 678 MW to 893 MW which is higher than "Light Load". PSC did not test other load levels between 678 MW and 893 MW.
6.18	SBA	Are the results sensitive to the location of the conventional resources online? For example, do the inertia benefits depend on electrical proximity of the conventional resource to the evaluated location (Woodbine substation)?
		While inertia is independent of locations, inertia is only one factor of many. Other factors include system short circuit strength, system stability, and the location of conventional resources in relation to load centers – all of which could influence the results of the study.
6.19	SBA	Are the results sensitive to the location of the incremental wind?
		Yes. Page 60 of the report states, "the final refined figure will depend on the specific location of any new wind generation."
6.20	SBA	In the evaluation of Case 04 with the additional tie (Section 5.2), were the same mitigation measures implemented as described in the base case (additional thermal unit, shunts switched off)?
		For Case 4 two thermal units are online but shunts are not switched off.
6.21	SBA	In the examination of the cases with the additional 345 kV tie, does the additional tie change the level of MW import/export from/to New Brunswick?
		Yes; however, the focus of the study was to estimate the level of additional wind the second tieline could accommodate.
6.22	SBA	In order to provide additional value to the planning process, the SBA believes the study should be expanded. It is our understanding that the study showed system integrity issues under some scenarios, even at the current 600MW level of renewable energy inverter based generation. This needs to be examined closely as enabling investment may be necessary in the near term, much earlier than a new interconnection could be planned, approved, constructed and energized.
		NS Power concurs that further study is required to determine with confidence the amount or variable renewable energy (or inverter based energy) that can be integrated into the power system; both the current system and with system upgrades (including those studied in the PSC report and/or other nearer term options). As discussed in Section 3.4, NS Power is working on translating the initial results of the PSC study into planning level constraints that reflect the study findings and provide options to reflect the costs of further inverter-based resource additions. These planning level constraints will be shared with stakeholders for discussion as part of the Assumptions Development phase of the IRP.
6.23	SBA	While this study provides a high-level insight into grid challenges and capabilities, it does not yet provide enough analysis or detail to base long-term investment decisions. Therefore, while it can assist with the strategic-level discussions during the IRP process, additional study will be required to

		fully understand the costs, benefits and trade-offs of different solutions for integrating additional renewables.
		As discussed in Section 3.4, this study was specifically focused on stability and system strength. The costs, benefits and trade-offs of different solutions for renewable integration will be examined in the IRP modeling. More detail on the approach for this evaluation will be provided in the Analysis Plan for the IRP.
6.24	E1	Curtailment of wind and dispatchable wind are solutions in other jurisdictions, as are Remedial Action Schemes. Were these options considered in the study to increase integration of additional renewable/variable output generation?
		As discussed in Section 3.4, transient stability studies like the PSC study are focused on the first few cycles after a system disturbance. During this time (inertial response), the kinetic energy stored in the system during the pre-fault condition is the only force that can slow down the frequency declining rate, which is critical for system stability. This is discussed on page 14, Section 2.1 of the Stability Study (Attachment 19) regarding South Australia: "AEMO also investigated the possibility of using fast frequency response (FFR) provided by inverter-based systems to compensate for the reduction in inertia. However, it was found that the time delays required for accurate frequency measurement would still make it necessary to have sufficient inertia online." NSPI extensively uses Remedial Action Schemes to manage transmission congestion, and it was included in the PSC study. Manual curtailment of wind during light load periods was also used in the PSC study. As discussed in Section 3.4, these options may also be considered in more detail (particularly curtailment) through the economic analysis.
6.25	E1	What level of DSM was assumed for the study? • How do demand savings achieved through demand side management affect renewables integration? • How does the level of demand response affect renewables integration?
		The levels of demand side management, including DR, do not affect renewable integration from a transient stability perspective. As discussed in Section 3.4, this will be examined from an economic perspective in the IRP modeling.
6.26	Envigour	Please describe the implications for balancing wind once market priced hydro from Muskrat Falls is available in 2020/2021? Will the presence of the market block be helpful in integrating the current wind on the system (600 MW), and if not why not? And what role would the market block play in helping to balance additional invertor-based electricity resources (wind or solar or tidal) [please reference the value of the Nalcor/NS Power annual RFP process and how it could be used to help balance wind].
		Access to economic import energy both from the surplus market block as well as general market priced purchases above the block are expected to improve the economics of the integration of existing and future wind. Since

		the prices of market energy are expected to be below that of the utility's current marginal cost and other new dispatchable resource options (e.g. natural gas units), the cost to backfill wind generation during hours of low or non-production is expected to decrease due to the access to the potential energy purchases. As discussed in Section 3, this economic benefit will be reflected in the long-term resource optimization modeling conducted in the IRP.

Topic 7: Demand Response & Demand Side Programs		
#	**Party**	**Question/Comment & Response**
7.1	Bates White	How will the results of the EE/DR potential study be incorporated in the IRP modeling?
		The EE/DR assumptions and scenarios, as well as plan for incorporating in the model, will be established in the development of the Analysis Plan and Assumptions during the IRP process, as discussed in Section 3.
7.2	Bates White	Do the base, low and high scenarios examined in the EE/DR potential study correspond to scenarios that are expected to be applied in the IRP modeling? If not, how will the EE/DR case results be mapped to IRP analysis scenarios?
		Please refer to response 7.1.
7.3	Bates White	It is stated in 1.3.1 Program Design (page 17) that "this potential study is not intended to provide, nor does it have information on, detailed program designs." Please clarify whether the study assessed NSPI's existing EE/DR programs in developing the EE/DR potential estimates presented in the report
		E1 has provided a response to this question on page 2 of Attachment A-4.
7.4	Bates White	Regarding the caveat in 1.3.1 Program Design (page 17), that "[d]different program designs and delivery mechanisms would inevitably result in different levels of adoption of efficient technologies…", will NSPI in its IRP analyses assume new EE/DR program to achieve increased EE/DR?
		As per the Pre-IRP deliverables, NS Power has proposed specific DR programs for consideration in the IRP. During the Assumptions Development phase, additional DR and DSM (EE) programs may be identified for inclusion in the IRP modeling.
7.5	Bates White	Regarding the bulleted item "Residential HVAC Fuel Switching" under 12.1 Energy Efficiency (page 118), please describe more fully the assumed "HVAC fuel switching measures that completely remove the end-use load from a home." Were the associated estimates of EE technical and economic potential based on actual fuel costs faced by NSPI residential customers?
		E1 has provided a response to this question on page 3 of Attachment A-4.
7.6	Bates White	What are the "significant market barriers to customer adoption" of HVAC fuel switching?
		E1 has provided a response to this question on page 3 of Attachment A-4.
7.7	Bates White	How will EE be treated in the IRP modeling process as load modifier or resource options. It will be important for NSPI to clearly specify the EE/DR

		scenarios that are modeled and to detail how such scenarios correspond to and/or deviate from the base, low and high scenarios examined in the EE/DR potential study.
		Please refer to response 7.1.
7.8	Bates White	We recommend that NSPI explicitly evaluate and report on the potential for EE/DR to mitigate near-term capacity deficits and to displace longer-term investments in existing and new supply resources as well as transmission.
		NSP agrees - both supply and demand side resources will be considered for capacity deficiency and/or economic optimization in the integrated resource planning process, consistent with past IRPs.
7.9	SBA	The SBA believes that to effectively conduct least-cost resource planning, the DR assumptions will be critical. Growth in intermittent and distributed generation, the electrification of transportation (and potentially heat), and the societal preference for non-emitting generation are trends that place a premium on load flexibility. Given the indication that battery storage is likely to be included in the portfolios to be evaluated in the IRP, we feel it is important that the DR assumptions be fully vetted by stakeholders prior to the analysis. NSPI has raised several concerns regarding high penetrations of intermittent resources, and the stakeholder session primarily discussed storage as a solution. DR utilizing direct load control can be a much more economical resource that serves a similar purpose, but NSPI so far has only presented very high-level assumptions that will be used in the IRP. There are several direct load control options that NSPI can consider beyond water heater load, including air conditioning, electrified heating, commercial refrigeration and even certain industrial loads.
		As discussed in Section 3, the Assumptions Development phase of the IRP will document the types and characteristics of DR and DERs resources evaluated. NS Power will work interested parties to develop reasonable assumptions for testing the economic viability of DR/DERs.
7.10	E1	How were assumptions developed regarding the enrollment fee as well as the annual incentive relating to hot water heaters?
		The assumptions regarding enrollment and ongoing incentives are developed based on the utility DR programs jurisdictional review. We also made direct contact with some of utilities in Canada and the United States for their information sharing.
7.11	E1	What costs are included in the $1.49/MW program cost? And was this discounted over the 25 years?
		The cost breakdowns line items are included in Attachment A-5. Costs are not discounted over 25 years.
7.12	E1	Are the costs inclusive of expected costs at the system operator level to enable hot water heater direct load control?
		The cost of system operator level such as DRMS is included for direct load control. Because DR will be considered as a dispatchable resource integrated with routine day-ahead dispatching planning and real-time system operation, we don't see additional resource needed regarding the operation at system level.
7.13	E1	What technology is anticipated to be used for the control devices?
		• Device level technologies include switch controllers for water

		heater and EV and controllable inverters for battery. • Communication technology is to be determined. Preferably to leverage on smart meters and AMI infrastructure as home energy management gateway solutions. • Aggregator level technologies consider using vendor or manufacturer's cloud based service platforms for device level dispatch and load forecasting. • Utility level technologies includes DERMS for facilitating the resource dispatch and program administration
7.14	E1	Did E3 use its own forecast for EV sales in Nova Scotia or was this taken from the NS Power Load Forecast?
		The EV sales forecast was taken from NS Power's 2019 Load Forecast.
7.15	E1	Please provide assumptions for EV program costs over the 25 years
		Please refer to Attachment A-5.
7.16	E1	How was E1 information on DR programs, and the draft potential study, used to inform the 3 DR programs?
		As discussed with E1 since this question was submitted, E1 and NSP can reconcile the assumptions on both technical and marketing parameters. E1 and NSP will also review and gauge realistic assumptions for product penetration (especially battery adoption) and DR program uptake forecasting.
7.17	E1	Please provide detailed assumptions with sources for NSP's DR program analysis. It may be beneficial to walk-through these assumptions in the next pre-IRP stakeholder session time permitting. More specifically, can NSP provide further details on the following: a) Annual EV forecast through 2045 (if different than the forecast used in the 2019 NSP Load Forecast) b) Event opt-out assumptions c) Program attrition assumptions d) Recurring costs as technologies such as water heaters, electric vehicles, and advanced controls reach their end of life e) All other program cost assumptions f) How the total peak shaving potential for each DR program has been calculated
		NSP and E1 met to discuss these questions following their submission. Please refer to Attachment A-5. a) Please refer to response 7.14. b) Event opt-out assumptions have not been considered in these preliminary assumptions. c) Please refer to Attachment A-5. d) Please refer to Attachment A-5. e) Please refer to Attachment A-5. f) The DR potential for peak shaving is based on the hourly load research data and coincident peak analysis.
7.18	E1	The footnote on the first page of the DR Program Overview document

		references behavior-based peak shifting through time-varying rates. Have the peak shaving potential and program costs been quantified for these programs?
		Behavior based DR and time-varying rates will be considered separately, and was not in the scope of the IRP DR work to date, which focuses on direct load control.
7.19	Verschuren Centre	In comparison to the Demand Response Draft Assumption Summary (Attachment 3 - Slide 1), this ETS unit would have closer to 19.2kW of peak shaving capacity. To achieve a MW of demand response at this rate, approximately 52 units would be needed, at a cost of $0.52M/MW. With a long design life, the lifetime cost would be significantly less than any options currently listed. With respect to the Effective Load Carrying Capability (ELCC) of storage and demand response (E3 Capacity Study Overview –Slide 25), this ETS example is in the higher range of hours of energy storage (6-12hours) and is available for more than 20 calls / year considered in the demand response graphic. Therefore, this ETS would be at the upper range or higher in Effective Load Carrying Capability than those attributes graphed in the presentation, and a significant amount of investment would be available in thermal storage before diminishing returns applied in a material manner. The cost effectiveness advantage is even more drastic when compared to other storage/capacity options based on duration, versus capacity. Since the cost of additional material is low in an ETS system, the cost per kWh is also low. The ETS example from above yields an installed capital cost per kWh of $83.
		NS Power's DR programs focused on a small subset of many potential DR programs for IRP consideration (specifically “Active DR” programs, which are utility driven and have the direct ability to control the load at the customer site). NS Power will consider this information in the Assumptions Development Phase of the IRP.
7.20	Verschuren Centre	Demand Response Customer Incentives. What are these incentives based on? Who owns the equipment in these models? There many are benefits to both customer owned models, or utility owned models. It would be important for customers to receive an appropriate benefit. In some markets (Tempus Energy – UK) demand response equipment is owned by the utility, and participating customers receive a reduced energy rate as a result.
		Please refer to response 7.10 and Attachment A-5.

Appendix A – Attachment A-1

E3 Wind Profiles Actual vs Simulation

Has been added to irp.nspower.ca

In electronic format

Hydro Asset Sustaining Capital - with Allocated Balance of Plant (Present Value $Millions)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Avon River	0.05	0.05	5.00	1.98	1.53	0.05	0.05	0.05	0.05	0.20	0.05
Bear River	1.10	1.20	0.70	3.68	0.10	0.10	0.10	0.65	1.75	0.35	0.20
Black River	15.45	2.35	4.45	3.90	3.50	1.85	0.50	0.50	1.10	0.75	0.25
Dickie Brook	0.10	2.60	0.10	0.50	0.58	0.10	0.38	0.10	0.10	0.10	0.10
Fall River	1.63	0.05	0.05	0.05	0.05	0.15	0.98	0.05	0.05	0.05	0.05
Lequille	0.05	0.05	1.05	0.05	0.05	0.25	0.05	0.05	0.05	0.30	0.15
Mersey*	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Nictaux	0.05	0.15	0.05	0.05	0.55	0.38	0.50	1.05	0.05	0.05	0.30
Paradise	0.90	3.55	0.80	0.05	0.05	0.70	0.30	0.05	0.05	0.05	0.05
Sheet Harbour	11.73	4.30	0.55	0.80	0.75	0.30	0.45	0.30	0.30	0.30	0.80
Sissiboo	1.70	0.30	2.20	0.20	4.20	2.10	0.70	0.20	0.20	0.45	0.45
St Margarets Bay	2.80	1.60	0.30	0.30	0.30	6.80	1.55	1.80	0.30	0.50	0.30
Tusket	2.25	1.05	0.15	0.65	0.15	0.15	0.15	0.15	0.15	0.15	0.30
Wreck Cove	6.50	31.70	26.70	0.15	9.85	0.15	0.15	0.65	0.15	0.15	1.15
Grand Total (Millions)	**$ 44.9**	**$ 49.6**	**$ 42.7**	**$ 13.0**	**$ 22.3**	**$ 13.7**	**$ 6.5**	**$ 6.2**	**$ 4.9**	**$ 4.0**	**$ 4.8**

*Note: The forecast for the Mersey system shows only balance of plant sustaining capital. A Capital Application to the UARB for the Mersey Redevelopment Project is currently in development.

Steam Historical Spend

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Lingan Generating Station	$ 30,547,798	$ 31,655,777	$ 36,439,589	$ 13,213,561	$ 7,120,702	$ 7,020,611	$ 8,914,359	$ 34,601,539	$ 28,597,555	$ 12,200,851	$ 17,064,327
Lingan Unit 1	$ 6,849,500	$ 3,832,520	$ 14,938,826	$ 823,452	$ 389,574	$ 1,201,496	$ 607,993	$ 1,891,896	$ 312,479	$ 3,143,922	$ 2,888,036
Lingan Unit 2	$ 274,244	$ 2,572,349	$ 3,307,036	$ 2,786,963	$ 490,314	$ 508,261	$ 646,633	$ 727,349	$ 75,990	$ 266,223	$ 329,243
Lingan Unit 3	$ 3,012,137	$ 8,090,432	$ 1,592,524	$ 1,961,621	$ 640,901	$ 1,186,524	$ 1,327,522	$ 20,848,463	$ 867,063	$ 186,685	$ 4,063,778
Lingan Unit 4	$ 2,969,143	$ 5,714,017	$ 1,465,866	$ 1,690,010	$ 857,207	$ 1,120,706	$ 1,794,468	$ 2,871,751	$ 19,905,287	$ 407,584	$ 2,580,326
Lingan Common Plant	$ 17,442,775	$ 11,446,459	$ 15,135,337	$ 5,951,515	$ 4,742,706	$ 3,003,624	$ 4,537,742	$ 8,262,080	$ 7,436,735	$ 8,196,438	$ 7,202,943
Point Aconi Generating Station	$ 5,930,440	$ 3,865,295	$ 3,883,165	$ 23,294,535	$ 11,242,425	$ 5,742,975	$ 12,715,208	$ 10,379,396	$ 13,285,924	$ 17,048,660	$ 14,393,435
Point Aconi	$ 5,930,440	$ 3,865,295	$ 3,883,165	$ 23,294,535	$ 11,242,425	$ 5,742,975	$ 12,715,208	$ 10,363,928	$ 13,219,646	$ 17,048,660	$ 14,393,435
Point Aconi Common Plant								$ 15,468	$ 66,279		
Point Tupper Generating Station	$ 10,811,660	$ 5,062,870	$ 6,651,397	$ 24,780,981	$ 3,897,650	$ 5,587,484	$ 3,325,003	$ 9,946,910	$ 4,744,067	$ 6,851,350	$ 4,237,839
Point Tupper Unit 2	$ 1,571,740	$ 2,443,154	$ 2,000,552	$ 1,618,079	$ 1,711,702	$ 569,776	$ 856,112	$ 912,828	$ 950,128	$ 6,851,350	$ 4,237,839
Point Tupper Common Plant	$ 9,239,921	$ 2,619,715	$ 4,650,845	$ 23,162,902	$ 2,185,948	$ 5,017,708	$ 2,468,891	$ 9,034,082	$ 3,793,939		
Port Hawkesbury Biomass			$ 86,289,134	$ 63,357,082	$ 148,302,354	$ 7,917,517	$ 2,270,684	$ 1,168,767	$ 1,214,729	$ 1,119,622	$ 1,347,239
Port Hawkesbury Biomass			$ 86,289,134	$ 63,357,082	$ 148,302,354	$ 7,917,517	$ 2,270,684	$ 1,168,767	$ 1,214,729	$ 1,119,622	$ 1,347,239
Trenton Generating Station	$ 16,135,343	$ 46,634,826	$ 29,323,453	$ 7,618,582	$ 22,415,643	$ 8,669,024	$ 6,960,108	$ 20,380,063	$ 19,408,446	$ 24,769,636	$ 11,027,348
Trenton Unit 5	$ 7,899,390	$ 43,030,839	$ 18,836,440	$ 2,418,301	$ 12,820,628	$ 1,677,059	$ 4,315,224	$ 4,804,609	$ 6,503,743	$ 4,065,216	$ 5,905,699
Trenton Unit 6	$ 5,822,442	$ 2,097,997	$ 7,404,855	$ 1,326,474	$ 1,611,237	$ 4,457,648	$ 750,690	$ 6,854,553	$ 2,270,186	$ 17,521,272	$ 1,825,757
Trenton Common Plant	$ 2,413,510	$ 1,505,990	$ 3,082,158	$ 3,873,807	$ 7,983,778	$ 2,534,316	$ 1,894,195	$ 8,720,902	$ 10,634,516	$ 3,183,148	$ 3,295,892
Tufts Cove Generating Station	$ 14,503,427	$ 45,059,762	$ 57,437,514	$ 15,964,798	$ 15,051,274	$ 14,231,504	$ 10,436,216	$ 6,211,681	$ 13,973,865	$ 14,889,286	$ 12,135,511
Tufts Cove Unit 1	$ 725,587	$ 4,718,467	$ 4,636,441	$ 1,819,152	$ 277,094	$ 725,358	$ 101,454	$ 933,066	$ 4,458,074	$ 178,212	$ 1,302,853
Tufts Cove Unit 2	$ 1,037,914	$ 3,928,280	$ 476,703	$ 256,484	$ 5,031,935	$ 8,280,458	$ 761,702	$ 1,301,103	$ 1,971,541	$ 4,220,510	$ 3,168,632
Tufts Cove Unit 3	$ 1,637,492	$ 5,514,213	$ 4,463,693	$ 382,613	$ 6,689,945	$ 1,214,008	$ 3,271,041	$ 2,013,057	$ 883,408	$ 7,543,438	$ 1,112,705
Tufts Cove Unit 6	$ 8,818,975	$ 29,783,718	$ 46,532,674	$ 11,708,770	$ 860,863	$ 312,782	$ 1,407,478	$ 1,919	$ 428,291	$ 106,686	$ 1,508,568
Tufts Cove Common Plant	$ 2,283,459	$ 1,115,083	$ 1,328,002	$ 1,797,779	$ 2,191,437	$ 3,698,898	$ 4,894,541	$ 1,962,535	$ 6,232,551	$ 2,840,441	$ 5,042,754
Grand Total - Steam	**$ 77,928,669**	**$ 132,278,530**	**$ 220,024,252**	**$ 148,229,539**	**$ 208,030,048**	**$ 49,169,115**	**$ 44,621,578**	**$ 82,688,357**	**$ 81,224,587**	**$ 76,879,406**	**$ 60,205,699**

Combustion Turbines Historical Spend

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Burnside CT	$ 88,761	$ 116,184	$ 299,345	$ 212,092	$ 1,988,602	$ 1,329,079	$ 3,419,576	$ 3,605,280	$ 3,705,852	$ 7,322,586	$ 2,467,601
Burnside Unit 1	$ 31,530	$ 116,184	$ 280,662	$ 24,267	$ 1,637,254	$ 610,906	$ 3,181	$ 222,079	$ 244,689	$ 81,031	$ 48,824
Burnside Unit 2	$ 57,232					$ 168,546		$ 99,062	$ 178,512	$ 3,281,529	$ 26,207
Burnside Unit 3						$ 94,003	$ 1,890,238	$ 847,514	$ 379,142	$ 56,397	$ 6,408
Burnside Unit 4							$ 1,450,826	$ 2,332,330	$ 302,498	$ 3,261,519	$ 2,294,488
Burnside Common Plant			$ 18,683	$ 187,825	$ 351,348	$ 455,624	$ 75,330	$ 104,296	$ 2,601,010	$ 642,109	$ 91,675
Gas Turbine General									$ 24,649	$ 1,833,417	$ (796,834)
Gas Turbine General									$ 24,649	$ 1,833,417	$ (796,834)
LM6000	$ 2,106,812	$ 4,950,361	$ 8,978,494	$ 3,293,551	$ 7,396,754	$ 8,593,681	$ 4,544,188	$ 7,674,063	$ 3,254,224	$ 4,429,159	$ 2,532,279
Tufts Cove Unit 4		$ 4,048,033	$ 4,868,724	$ 20,150	$ 6,588,265	$ 8,593,071	$ 1,464,958	$ 1,932,652	$ 1,704,764	$ 2,025,776	$ 1,832,925
Tufts Cove Unit 5	$ 2,106,812	$ 902,328	$ 4,109,770	$ 3,273,401	$ 808,489	$ 610	$ 3,079,230	$ 5,741,145	$ 1,444,063	$ 2,229,737	$ 432,236
Tufts Cove LM6000 Common Plant								$ 266	$ 105,397	$ 173,647	$ 267,117
Tusket Combustion Turbine	$ 173,007	$ 137,898	$ 160,632	$ 180,893	$ 301,835	$ 2,716,078	$ 284,563	$ 448,499	$ 699,625	$ 3,390,059	$ 1,946,893
Tusket Combustion Turbine	$ 173,007	$ 137,898	$ 160,632	$ 180,893	$ 301,835	$ 2,716,078	$ 284,563	$ 448,499	$ 699,625	$ 3,390,059	$ 1,946,893
Victoria Junction			$ 80,145	$ 21,627	$ 3,986	$ 223,806	$ 25,180	$ 3,584	$ 5,907	$ 948,932	$ 311,046
Victoria Junction Unit 1						$ 164,233			$ 5,907	$ 574,510	$ 64,681
Victoria Junction Unit 2										$ 51,819	$ 77,478
Victoria Junction Common Plant			$ 80,145	$ 21,627	$ 3,986	$ 59,574	$ 25,180	$ 3,584		$ 322,603	$ 168,887
Grand Total - Combustion Turbine	**$ 2,368,580**	**$ 5,204,444**	**$ 9,518,616**	**$ 3,708,162**	**$ 9,691,177**	**$ 12,862,645**	**$ 8,273,506**	**$ 11,731,426**	**$ 7,690,257**	**$ 17,924,153**	**$ 6,460,986**

Wind Historical Spend

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Wind General		$ 32,730,326	$ 194,688,451	$ 71,835,518	$ 7,387,597	$ 9,095,966	$ 83,049,153	$ 18,777,031	$ 1,391,405	$ 474,231	$ 237,458
1300 Digby Wind Farm			$ 64,742,447	$ 66,705,261	$ 179,840	$ 20,648		$ 1,100	$ 413,130	$ 5,742	$ 390
1303 Nuttby Wind Farm		$ 24,856,262	$ 86,285,336	$ 1,916,894	$ 59,922	$ 28					
1304 Sable Wind Farm				$ 10,022	$ 443,106	$ 289,834	$ 10,369,154	$ 1,825,493	$ 3,699	$ (699)	$ 89
1305 South Canoe Wind Farm					$ 2,011,855	$ 8,647,060	$ 72,498,066	$ 16,871,966	$ 847,702	$ (2,643)	$ 110,223
1306 Point Tupper Wind Farm		$ 7,874,065	$ 42,276,763	$ 69,866							
Grand Etand Wind Farm										$ 404,019	$ 15,423
Little Brook Wind											$ 325,449
1310 Wind General			$ 1,383,904	$ 3,133,475	$ 4,692,875	$ 138,395	$ 181,932	$ 78,472	$ 126,874	$ 67,812	$ (214,115)
Grand Total - Wind		**$ 32,730,326**	**$ 194,688,451**	**$ 71,835,518**	**$ 7,387,597**	**$ 9,095,966**	**$ 83,049,153**	**$ 18,777,031**	**$ 1,391,405**	**$ 474,231**	**$ 237,458**

Hydro Historical Spend

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Annapolis	$ 94,464	$ 199,423	$ 286,147	$ 403,172	$ 1,135,321	$ 1,746,898	$ 752,748	$ 1,529,834	$ 3,174,290	$ 969,121	$ 1,611,900
Avon River	$ 10,520	$ 24,597	$ 33,001	$ 4,146,695	$ 188,041	$ 18,833	$ 90,744	$ 1,960,249	$ 302,244	$ 149,012	$ 899,984
Bear River	$ 82,331	$ 3,309,789	$ 591,596	$ 606,234	$ 1,046,230	$ 493,366	$ 86,792	$ 1,150	$ 1,114,912	$ 4,702,721	$ 1,182,800
Black River	$ 5,030,356	$ 5,454,134	$ 9,694,703	$ 1,816,683	$ 2,421,291	$ 5,404,477	$ 490,943	$ 2,095,480	$ 7,738,220	$ 3,364,015	$ 1,234,441
Dickie Brook	$ 3,870,422	$ 1,830,736	$ 2,611,601	$ 729,245	$ 1,307,377	$ 254,687	$ 413,833	$ 265,996	$ 40,952	$ 26,958	$ 291,061
Fall River	$ 68,681	$ 323,767	$ 813,740	$ 760	$ 422		$ 5,696		$ 426,499	$ 33,295	$ (14,562)
Harmony River	$ 15,790	$ 60,529	$ 4,904	$ 22,481	$ 160,769	$ 120,284	$ 852,772	$ 167,757	$ 78,816	$ 299,011	$ 41,145
Hydro General	$ 961,721	$ 8,914,852	$ 1,878,031	$ 3,076,679	$ 3,407,846	$ 1,577,241	$ 854,003	$ 761,385	$ 771,181	$ 478,898	$ 3,803,242
Lequille River	$ 109,863	$ 3,831		$ 5,565	$ 545			$ 55,894	$ 264,603	$ 4,351,318	$ 6,518,644
Mersey River	$ 752,069	$ 1,182,576	$ 1,741,393	$ 7,296,881	$ 1,742,466	$ 883,159	$ 948,456	$ 1,452,715	$ 1,537,395	$ 1,544,450	$ 3,414,792
Nictaux River		$ 472,843	$ 851,670	$ 676,181	$ 116,870	$ 954,321	$ 2,817,922	$ 1,971,068	$ 1,338,983	$ 1,878,024	$ 113,119
Roseway River	$ 79,753	$ 201,957	$ 61,626	$ 14,785	$ 156,528	$ 111,134	$ 121	$ 60,299	$ 17,777	$ 3,930	$ (356,162)
Sheet Harbor	$ 352,461	$ 300,109	$ 318,008	$ 593,787	$ 1,690,010	$ 1,578,630	$ 1,555,425	$ 1,088,811	$ 1,823,393	$ 1,404,190	$ 405,071
Sissiboo River	$ 217	$ 108,185	$ 720,011	$ 262,845	$ 782,837	$ 10,273,974	$ 1,265,938	$ 3,647,656	$ 4,008,941	$ (25,213)	$ 2,359,994
St. Margaret's Bay	$ 415,580	$ 417,550	$ 3,303,460	$ 5,617,247	$ 16,841,814	$ 1,400,318	$ 2,014,346	$ 5,281,280	$ 7,647,418	$ 392,445	$ 466,377
Tusket River	$ 186,441	$ 1,069,117	$ 6,975,824	$ 1,425,946	$ 657,639	$ 257,446	$ 1,217,169	$ 468,613	$ 381,186	$ 3,580,586	$ 862,348
Wreck Cove	$ 274,921	$ 869,591	$ 1,223,742	$ 1,604,500	$ 1,688,610	$ 1,487,775	$ 6,977,664	$ 9,117,682	$ 7,728,346	$ 6,686,976	$ 7,325,187
Grand Total - Hydro	**$ 12,305,589**	**$ 24,743,587**	**$ 31,109,459**	**$ 28,299,686**	**$ 33,344,616**	**$ 26,562,544**	**$ 20,344,571**	**$ 29,925,868**	**$ 38,395,155**	**$ 29,839,742**	**$ 30,159,380**

MEMORANDUM

To: Nicole Godbout, Director of Regulatory Affairs, NS Power

From: Gina Thompson, Director of Finance and Regulatory Affairs, EfficiencyOne

Date: Tuesday, September 10, 2019

Re: NS Power Integrated Resource Plan: EfficiencyOne Responses to Bates White

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Question 01:

How will the results of the EE/DR potential study be incorporated in the IRP modeling?

EfficiencyOne was directed by the NSUARB to initiate a new DSM Potential Study for completion no later than July 31, 2019, to assess the availability of cost-effective DSM measures.[1] The NSUARB in its letter dated October 5, 2018 in Matter 08059 states"…the DSM Potential Study is a critical component in the IRP analysis…".[2] It is EfficiencyOne's understanding that the 2019 DSM Potential Study results will be used as an input in the IRP modelling. EfficiencyOne expects that determinations relating to the use of the 2019 Potential Study will be part of the development of an analysis plan associated with the 2020 IRP.

Question 02:

Do the base, low and high scenarios examined in the EE/DR potential study correspond to scenarios that are expected to be applied in the IRP modeling? If not, how will the EE/DR case results be mapped to IRP analysis scenarios?

EfficiencyOne expects that the scenarios developed in the 2019 DSM Potential Study will be directly applied but recognizes that Stakeholder discussion on this topic has not yet occurred. EfficiencyOne expects determinations relating to the use of the 2019 Potential Study to be part of the development of an analysis plan associated with the 2020 IRP.

Question 03:

It is stated in 1.3.1 Program Design (page 17) that "this potential study is not intended to provide, nor does it have information on, detailed program designs." Please clarify whether the study assessed NSPI's existing EE/DR programs in developing the EE/DR

[1] M08604 Board Order, July 23, 2018, page 2.
[2] M08059 Board Letter, October 5, 2018, page 3.

MEMORANDUM

potential estimates presented in the report.

Neither the energy efficiency nor demand response portions of the 2019 Potential Study directly assessed existing program structures, given the forward-looking study period associated with those analyses, and the lack of currently existing Demand Response programs (beyond Interruptible Service for certain Industrial customers). The historical performance of certain measures and all end uses included in EfficiencyOne's existing energy efficiency programs were used for the calibration of the energy efficiency potential model. In addition, the Baseline Study performed by Navigant intended to capture the effects of historic and existing DSM programs in Nova Scotia, through recording current equipment types within the province. Finally, certain types of input data for energy efficiency measures, such as administrative costs, were based on historic NS program data.

Question 04:

Regarding the caveat in 1.3.1 Program Design (page 17), that "[d]ifferent program designs and delivery mechanisms would inevitably result in different levels of adoption of efficient technologies…", will NSPI in its IRP analyses assume new EE/DR programs to achieve increased EE/DR?

EfficiencyOne anticipates and recommends that the results of the energy efficiency and demand response Potential Studies be directly used in the context of the IRP. The demand response potential study is structured in the form of specific program designs, while the energy efficiency potential cases included in that Study are somewhat agnostic toward specific program designs. The cases included for energy efficiency potential are "free-standing" and should be generally used in their native format.

EfficiencyOne expects this topic to garner further discussion amongst Stakeholders during the preparation of the analysis plan associated with the 2020 IRP.

Question 05:

Regarding the bulleted item "Residential HVAC Fuel Switching" under 12.1 Energy Efficiency (page 118), please describe more fully the assumed "HVAC fuel switching measures that completely remove the end-use load from a home." Were the associated estimates of EE technical and economic potential based on actual fuel costs faced by

MEMORANDUM

NSPI residential customers?

It is important to note that Technical and Economic Potential do not limit energy efficiency potential based on customer economics (differing from Achievable Potential scenarios), and as such do not consider customer fuel costs directly. Within Economic Potential, incremental fuel costs associated with fuel-burning appliances are included as costs within the Total Resource Cost test, which screens measures for this potential type.

Program administrator spending estimates for all scenarios include incentive costs and the cost of administration, and as such do not include customer fuel costs.

Question 06:

What are the "significant market barriers to customer adoption" of HVAC fuel switching?

Market barriers, applicable to biomass fuel switching, include the somewhat significant labour involved in operating such a system, as well as the required storage for fuel, and the perceived "messiness" of solid fuel appliances. These market barriers are assumed to lead to reduced market penetration, through the inclusion of a non-economic payback adder (a reduction of required customer paybacks for acceptance and uptake). These effects are expected to be more pronounced with cordwood-based systems.

DR Program Calculator: Direct Control of Residential Battery

Year to Implement 2022 Cust Sector T: All Electric

Market Parameters

All Electric Home peak contribution (kW)	2.50	charging cycles per yr	10	outage duration (hr)	2.5				
	Price ($)	**Install Cost ($)**	**battery size (kWh)**	**discharge power (kW)**	**customer contribution ($)**	**DERMS subscription fee ($-yr)**	**Life cycle (yrs)**	**Deteriorate rate (%)**	**Round-trip efficiency**
Generic battery	15000	0	13.5	2.5	2500	0	10	50	1

DERMS assumption

additional capac	3	$/kW
Additional asset	13	$/unit

Prog Cost Parameters

Salary per FTE ($) 80000

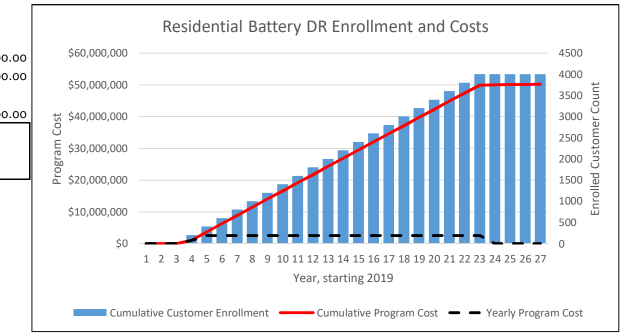
DR Program Parameters

	Generic	
Annual uptake increa	1	
Event calls	365	events/year
Event duration	4	hours/event

ESP assumption

Additional MW	Price	Number of Resid	Price
25	$83,000.00	1000	$14,000.00
50	$145,000.00	5000	$65,000.00
100	$255,000.00	10000	$126,000.00
3	$/kW	13	$/unit

Annual fee $148,805.00



		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Year of Program		1	2	3	4	5	6	7	8	9	10	11	12	13
Program Uptake Forecasting	Total													
Generic battery uptake		0	0	0	200	200	200	200	200	200	200	200	200	200
Cumulative uptake		0	0	0	200	400	600	800	1000	1200	1400	1600	1800	2000
Load Impact														
Incremental load connected (KWh)		0	0	0	27000	27000	27000	27000	27000	27000	27000	27000	27000	27000
Incremental peak contribution (MW)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DR peak shaving (MW)		0.00	0.00	0.00	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.25
Cumulative load increase (GWh)		0.00	0.00	0.00	0.03	0.05	0.08	0.11	0.14	0.16	0.19	0.22	0.24	0.27
Cumulative net peak shaving (MW)		0.00	0.00	0.00	0.50	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50	4.75
Equipment and Installation														
Battery cost	$58,500,000	$0	$0	$0	$1,500,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000
Aggregation service cost	$480,000	$0	$0	$0	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000
DRMS service cost	$82,000	$0	$0	$0	$4,100	$4,100	$4,100	$4,100	$4,100	$4,100	$4,100	$4,100	$4,100	$4,100
Customer contribution	$10,000,000				$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000
Total E&I cost yr	$49,062,000	$0	$0	$0	$1,024,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100
Program Administration Cost														
Marketing	$187,500	$0	$0	$0	$20,000	$20,000	$20,000	$20,000	$20,000	$10,000	$10,000	$10,000	$10,000	$10,000
Program Management	$960,000	$0	$0	$0	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000
Total Program Adminstration Cost (M$)	$1,147,500	$0	$0	$0	$60,000	$60,000	$60,000	$60,000	$60,000	$50,000	$50,000	$50,000	$50,000	$50,000
Cost Benefit Analysis														
Total Program Cost (yearly)	$50,209,500	$0	$0	$0	$1,084,100	$2,584,100	$2,584,100	$2,584,100	$2,584,100	$2,574,100	$2,574,100	$2,574,100	$2,574,100	$2,574,100
	Cumulative Customer Enr	0	0	0	200	400	600	800	1000	1200	1400	1600	1800	2000
	Cumulative Program Cost	$0	$0	$0	$1,084,100	$3,668,200	$6,252,300	$8,836,400	$11,420,500	$13,994,600	$16,568,700	$19,142,800	$21,716,900	$24,291,000
	Yearly Program Cost	$0	$0	$0	$1,084,100	$2,584,100	$2,584,100	$2,584,100	$2,584,100	$2,574,100	$2,574,100	$2,574,100	$2,574,100	$2,574,100

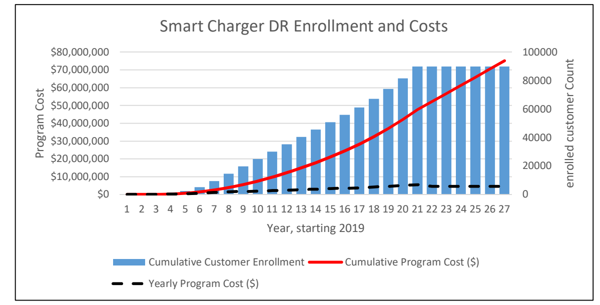
	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Year of Program	14	15	16	17	18	19	20	21						
Program Uptake Forecasting														
Generic battery uptake	200	200	200	200	200	200	200	200	200	200				
Cumulative uptake	2200	2400	2600	2800	3000	3200	3400	3600	3800	4000	4000	4000	4000	4000
Load Impact														
Incremental load connected (KWh)	13500	13500	13500	13500	13500	13500	13500	13500	13500	13500	-13500	-13500	-13500	-13500
Incremental peak contribution (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00						
DR peak shaving (MW)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	-0.25	-0.25	-0.25	-0.25
Cumulative load increase (GWh)	0.28	0.30	0.31	0.32	0.34	0.35	0.36	0.38	0.39	0.41	0.39	0.38	0.36	0.35
Cumulative net peak shaving (MW)	5.00	5.25	5.50	5.75	6.00	6.25	6.50	6.75	7.00	7.25	7.00	6.75	6.50	6.25
Equipment and Installation														
Battery cost	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$0	$0	$0	$0
Aggregation service cost	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000
DRMS service cost	$4,100	$4,100	$4,100	$4,100	$4,100	$4,100	$4,100	$4,100	$4,100	$4,100	$0	$0	$0	$0
Customer contribution	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$0	$0	$0	$0
Total E&I cost yr	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$2,524,100	$20,000	$20,000	$20,000	$20,000
Program Administration Cost														
Marketing	$5,000	$5,000	$5,000	$5,000	$5,000	$2,500	$2,500	$2,500	$2,500	$2,500				
Program Management	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000
Total Program Adminstration Cost (M$)	$45,000	$45,000	$45,000	$45,000	$45,000	$42,500	$42,500	$42,500	$42,500	$42,500	$40,000	$40,000	$40,000	$40,000
Cost Benefit Analysis														
Total Program Cost (yearly)	$2,569,100	$2,569,100	$2,569,100	$2,569,100	$2,569,100	$2,566,600	$2,566,600	$2,566,600	$2,566,600	$2,566,600	$60,000	$60,000	$60,000	$60,000
Cumulative Customer Enr	2200	2400	2600	2800	3000	3200	3400	3600	3800	4000	4000	4000	4000	4000
Cumulative Program Cost	$26,860,100	$29,429,200	$31,998,300	$34,567,400	$37,136,500	$39,703,100	$42,269,700	$44,836,300	$47,402,900	$49,969,500	$50,029,500	$50,089,500	$50,149,500	$50,209,500
Yearly Program Cost	$2,569,100	$2,569,100	$2,569,100	$2,569,100	$2,569,100	$2,566,600	$2,566,600	$2,566,600	$2,566,600	$2,566,600	$60,000	$60,000	$60,000	$60,000

Author:	Title:	
Zheng Qin	**DR-IRP Program: Home battery Direct Control**	
Check:		
Debra McLellan		
Approval:	**Date:**	**Revision:**
	8/30/2019	v1.1

DR Program Calculator: Direct Control of EV smart charging

Year to Implement	2022					
Market Parameters						
EV Average Peak Contribution (kW)	1.30	EV peak shaving (kW)		0.70		
	Estimate uptake	Smart Charger Rebate ($)	Smart Charger Install Cost ($)	Usage (kWh-yr)	Peak Contribution (kW)	
EV Average	70.00%	0		3059	1.3	
Smart charger cost ($)		Aggregator fee				
Infrastructure upgrade ($)						
Incentives Parameters			**DERMS assumption**			
One time enrollment ($)	150		additional capa	3	$/kW	
On going incent/yr ($)	50		Additional asset	13	$/unit	

Prog Cost Parameters			
Salary per FTE (	80000		
DR Program Parameters			
	PHEV	BEV	
Annual uptake	1	1	
Event calls	150	events/year	
event duration	2	hours/event	



		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Year of Program		1	2	3	4	5	6	7	8	9	10	11	12	13
Program Uptake Forecasting	Totalization													
Cumulative EVs		413	784	1490	2756	4961	8681	14757	22136	29515	36894	44272	51651	59030
Incremental Evs		413	371	706	1266	2205	3720	6077	7379	7379	7379	7379	7379	7379
DR Uptake	89704	0	0	0	886	1543	2604	4254	5165	5165	5165	5165	5165	5165
Load Impact														
Incremental load connected (GWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Incremental peak contribution (MW)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
DR peak shaving (MW)		0.00	0.00	0.00	0.62	1.08	1.82	2.98	3.62	3.62	3.62	3.62	3.62	3.62
Cumulative load increase (GWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative net peak shaving (MW)		0.00	0.00	0.00	0.62	1.70	3.52	6.50	10.12	13.73	17.35	20.96	24.58	28.19
Equipment and Installation														
EV smart charger rebate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Aggregator Cost					$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000
DRMS platform dev	$1,516,003	$0	$0	$0	$14,979	$26,081	$44,012	$71,886	$87,291	$87,291	$87,291	$87,291	$87,291	$87,291
Total E&I cost yr	$1,996,003	$0	$0	$0	$34,979	$46,081	$64,012	$91,886	$107,291	$107,291	$107,291	$107,291	$107,291	$107,291
Program Administration Cost														
Marketing	$182,500	$0	$0	$0	$20,000	$20,000	$20,000	$20,000	$20,000	$10,000	$10,000	$10,000	$10,000	$10,000
Program Management	$1,648,000	$0	$0	$0	$120,000	$120,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000
Incentive cost	$71,223,945	$0	$0	$0	$132,950	$275,807	$512,120	$889,738	$1,239,143	$1,497,399	$1,755,655	$2,013,911	$2,272,167	$2,530,423
Total Program Adminstration Cost (M	$73,054,445	$0	$0	$0	$272,950	$415,807	$596,120	$973,738	$1,323,143	$1,571,399	$1,829,655	$2,087,911	$2,346,167	$2,604,423
Cost Benefit Analysis (doesn't include rate adjustment)														
Total Program Cost (yearly)	$75,050,448	$0	$0	$0	$307,929	$461,888	$660,132	$1,065,624	$1,430,434	$1,678,690	$1,936,946	$2,195,202	$2,453,458	$2,711,714
	Cumulative Custon	0	0	0	886	2430	5034	9287	14453	19618	24783	29948	35113	40278
	Cumulative Progra	$0	$0	$0	$307,929	$769,817	$1,429,949	$2,495,573	$3,926,007	$5,604,696	$7,541,642	$9,736,844	$12,190,301	$14,902,015
	Yearly Program Co	$0	$0	$0	$307,929	$461,888	$660,132	$1,065,624	$1,430,434	$1,678,690	$1,936,946	$2,195,202	$2,453,458	$2,711,714

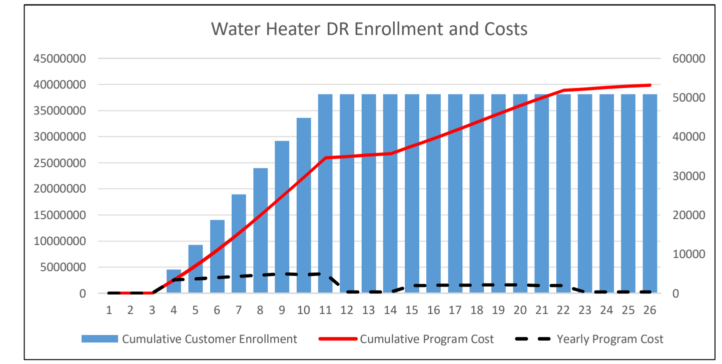
	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Year of Program	14	15	16	17	18	19	20	21						
Program Uptake Forecasting														
Cumulative EVs	66409	73787	81166	88545	97399	107139	117853	129639	129639	129639	129639	129639	129639	129639
Incremental Evs	7379	7379	7379	7379	8854	9740	10714	11785	0	0	0	0	0	0
DR Uptake	5165	5165	5165	5165	6198	6818	7500	8250	0	0	0	0	0	0
Load Impact														
Incremental load connected (GWh)														
Incremental peak contribution (MW)														
DR peak shaving (MW)	3.62	3.62	3.62	3.62	4.34	4.77	5.25	5.77	0.00	0.00	0.00	0.00	0.00	
Cumulative load increase (GWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative net peak shaving (MW)	31.81	35.43	39.04	42.66	47.00	51.77	57.02	62.79	62.79	62.79	62.79	62.79	62.79	62.79
Equipment and Installation														
EV smart charger rebate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Aggregator Cost	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000
DRMS platform dev	$87,291	$87,291	$87,291	$87,291	$104,749	$115,224	$126,746	$139,420	$0	$0	$0	$0	$0	$0
Total E&I cost yr	$107,291	$107,291	$107,291	$107,291	$124,749	$135,224	$146,746	$159,420	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000
Program Administration Cost														
Marketing	$5,000	$5,000	$5,000	$5,000	$5,000	$2,500	$2,500	$2,500						
Program Management	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000
Incentive cost	$2,788,679	$3,046,935	$3,305,192	$3,563,448	$3,976,657	$4,379,537	$4,822,704	$5,310,188	$4,485,215	$4,485,215	$4,485,215	$4,485,215	$4,485,215	$4,485,215
Total Program Adminstration Cost (M	$2,857,679	$3,115,935	$3,374,192	$3,632,448	$4,045,657	$4,446,037	$4,889,204	$5,376,688	$4,549,215	$4,549,215	$4,549,215	$4,549,215	$4,549,215	$4,549,215
Cost Benefit Analysis (doesn't include rate adjustment)														
Total Program Cost (yearly)	$2,964,970	$3,223,226	$3,481,482	$3,739,738	$4,170,406	$4,581,260	$5,035,950	$5,536,109	$4,569,215	$4,569,215	$4,569,215	$4,569,215	$4,569,215	$4,569,215
Cumulative Custon	45443	50608	55774	60939	67137	73955	81455	89704	89704	89704	89704	89704	89704	89704
Cumulative Progra	$17,866,985	$21,090,211	$24,571,693	$28,311,431	$32,481,837	$37,063,098	$42,099,048	$47,635,157	$52,204,372	$56,773,587	$61,342,802	$65,912,017	$70,481,232	$75,050,448
Yearly Program Co	$2,964,970	$3,223,226	$3,481,482	$3,739,738	$4,170,406	$4,581,260	$5,035,950	$5,536,109	$4,569,215	$4,569,215	$4,569,215	$4,569,215	$4,569,215	$4,569,215

Nova Scotia POWER An Emera Company	Author:	Title:	
	Zheng Qin	DR-IRP Program: EV Smart Charger Direct Control	
	Check:		
	Debra McLellan		
	Approval:	Date:	Revision:
		8/30/2019	v1.1

DR Program Calculator: Direct Control of Exisitng WH

Year to Implement	2022								
Market Parameters									**Prog Cost Parameters**
									Salary per FTE 80000
WH Average Peak Contribution (kW)	0.57	WH peak shaving (kW)		0.53					
	Res Percent	**Conversion Uptake**	**Existing uptake**	**On-bill financing and Rental Uptake**	**Price ($)**	**Install Cost ($)**	**Usage (kWh-yr)**	**Peak (kW)**	
Generic WH	100%	0%	2%	100%	520	520	3200	0.57	**DR Program Parameters**
Switch controller cost ($	169	controller install	200	one-visit discount	0.9				Conv. WH / Exist. WH
Incentives Parameters		**DERMS assumption**			**Aggregator:**				Annual uptake 1 / 1
One time enrollment ($	25	additional cap	3 $/kW		one time Servic	5000 $			Event calls 66 number/year
On going incent/yr ($)	25	Additional ass	13 $/unit		ongoing	2 $/unit/year			Event duration 2 hours/event

Nova Scotia POWER An Emera Company	Author: **Zheng Qin**	Title: **DR-IRP Program: WH Direct Control**
	Check: **Debra McLellan**	
	Approval:	Date: **8/30/2019** Revision: **V1.1**



		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2031
Year of Program		1	2	3	4	5	6	7	8	9	10	11	12
Program Uptake Foreca	Totalization												
EWH Market size		469054	471754	474454	477154	479854	482554	485254	487954	490654	493354	494,954	496,554
Market for conversion		236683	231984	227211	222362	217438	212439	207365	202216	196991	196546	195184	193988
AE homes		232371	239769	247243	254792	262415	270114	277889	285738	293662	296808	299769	302566
New Rental and finance		943	952	961	970	979	988	997	1006	1015			
Generic WH size		469997	472706	475415	478124	480833	483542	486251	488960	491669	493354	494954	496554
Uptake estimate for cor	0	0	0	0	0	0	0	0	0	0	0	0	0
Uptake estimate for exi	0	0	0	0	0	0	0	0	0	0	0	0	0
Uptake estimate for Ge	50779	0	0	0	6066	6227	6390	6555	6721	6888	5936	5995	0
Load Impact													
Incremental load connected (GWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incremental peak contribution (MW)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DR peak shaving (MW)		0.00	0.00	0.00	3.19	3.28	3.36	3.45	3.54	3.62	3.12	3.15	0.00
Cumulative load increase (GWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative net peak shaving (MW)		0.00	0.00	0.00	3.19	6.47	9.83	13.28	16.82	20.44	23.57	26.72	26.72
Equipment and Installation													
Switch controller install	$20,192,601	$0	$0	$0	$1,193,773	$1,225,892	$1,258,312	$1,291,032	$1,324,053	$1,357,375	$1,187,230	$1,199,078	$0
Switch controller cost	$8,581,698	$0	$0	$0	$1,025,132	$1,052,425	$1,079,972	$1,107,773	$1,135,828	$1,164,137	$1,003,210	$1,013,221	
Aggregator service	$1,985,681	$0	$0	$0	$17,132	$24,586.48	$37,367	$50,477	$63,919	$77,695	$89,568	$101,559	$101,559
DRMS platform dev	$1,695,511	$0	$0	$0	$10,386	$21,047	$31,988	$43,210	$54,715	$66,508	$76,671	$86,937	$86,937
Total E&I cost yr	$32,455,491	$0	$0	$0	$2,246,423	$2,323,951	$2,407,639	$2,492,492	$2,578,516	$2,665,715	$2,356,679	$2,400,793	$188,495
Program Administration Cost													
Marketing	$120,000	$0	$0	$0	$20,000	$20,000	$20,000	$20,000	$10,000	$10,000	$10,000	$10,000	
Program Management	$1,584,000	$0	$0	$0	$120,000	$120,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000
Incentive cost	$5,716,286	$0	$0	$0	$151,647	$307,331	$467,090	$630,962	$798,984	$971,194	$1,119,597	$1,269,482	$0
Total Program Adminstr	$7,420,286	$0	$0	$0	$291,647	$447,331	$551,090	$714,962	$872,984	$1,045,194	$1,193,597	$1,343,482	$64,000
Cost Benefit Analysis (doesn't include rate adjustment)													
Total Program Cost (yea	$39,875,778	$0	$0	$0	$2,538,070	$2,771,282	$2,958,729	$3,207,454	$3,451,499	$3,710,909	$3,550,276	$3,744,275	$252,495
	Cumulative Customer E	0	0	0	6066	12293	18684	25238	31959	38848	44784	50779	50779
	Cumulative Program C	$0	$0	$0	$2,538,070	$5,309,352	$8,268,081	$11,475,535	$14,927,035	$18,637,943	$22,188,220	$25,932,495	$26,184,990
	Yearly Program Cost	$0	$0	$0	$2,538,070	$2,771,282	$2,958,729	$3,207,454	$3,451,499	$3,710,909	$3,550,276	$3,744,275	$252,495

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Year of Program	13	14	15	16	17	18	19	20	21	22	23	24	25	
Program Uptake Foreca														
EWH Market size	498,154	499,754	501,354	502,954	504,554	506,154	507,754	509,354	509,354					
Market for conversion	192939	192024	191230	190544	189955	189454	189032	188680	188681					
AE homes	305215	307729	310124	312410	314599	316700	318722	320673	320673					
New Rental and finance														
Generic WH size	498154	499754	501354	502954	504554	506154	507754	509354	509354					
Uptake estimate for cor	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Uptake estimate for exi	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Uptake estimate for Ge	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Impact														
Incremental load connected (GWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incremental peak contribution (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DR peak shaving (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative load increase (GWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative net peak shaving (MW)	26.72	26.72	26.72	26.72	26.72	26.72	26.72	26.72	26.72	26.72	26.72	26.72	26.72	26.72
Equipment and Installation														
Switch controller install	$0	$0	$1,213,174	$1,245,473	$1,278,073	$1,310,974	$1,344,175	$1,377,678	$1,187,230	$1,199,078	$0	$0	$0	$0
Switch controller cost														
Aggregator service	$101,559	$101,559	$101,559	$101,559	$101,559	$101,559	$101,559	$101,559	$101,559	$101,559	$101,559	$101,559	$101,559	$101,559
DRMS platform dev	$86,937	$86,937	$86,937	$86,937	$86,937	$86,937	$86,937	$86,937	$86,937	$86,937	$86,937	$86,937	$86,937	$86,937
Total E&I cost yr	$188,495	$188,495	$1,401,669	$1,433,969	$1,466,569	$1,499,469	$1,532,671	$1,566,173	$1,375,725	$1,387,573	$188,495	$188,495	$188,495	$188,495
Program Administration Cost														
Marketing														
Program Management	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000
Incentive cost	$0	$0	$0	$0	$0	$0	$0	$0	$0					
Total Program Adminstr	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000	$64,000
Cost Benefit Analysis (doesn't include rate adjustment)														
Total Program Cost (yea	$252,495	$252,495	$1,465,669	$1,497,969	$1,530,569	$1,563,469	$1,596,671	$1,630,173	$1,439,725	$1,451,573	$252,495	$252,495	$252,495	$252,495
Cumulative Customer E	50779	50779	50779	50779	50779	50779	50779	50779	50779	50779	50779	50779	50779	50779
Cumulative Program C	$26,437,485	$26,689,980	$28,155,650	$29,653,618	$31,184,187	$32,747,656	$34,344,327	$35,974,499	$37,414,225	$38,865,797	$39,118,292	$39,370,787	$39,623,283	$39,875,778
Yearly Program Cost	$252,495	$252,495	$1,465,669	$1,497,969	$1,530,569	$1,563,469	$1,596,671	$1,630,173	$1,439,725	$1,451,573	$252,495	$252,495	$252,495	$252,495

Assumptions

Parameter/Assumptions	Description	Source
Year to Implement	The first year to roll out the program. Funding and resouces are allocated. Vendors and partners are determined. Regulatory approval should also be obtained.	IRP simulation year
NS Residential Count	NSP service customers, excluding TOD customers	Estimate
WH Installation Costs	Cost of labor and material charged by contractor. Assumed the same as the price of WH	Finding from rental program
Switch Controller Cost	The control device to enable Utility to shut off appliances when demand response event is called.	Power Shift Atlantic project
Installation Discount	To account for the reduced cost if installation of both WH and Switch Control device can be complete in one visit	Estimate
WH Average Peak Contribution	Coincident peak load of unit water heater. There is no break down of peak contribution by tank sizes.	10 year load forecasting
WH Peak Shaving	The differential between the coincident peak to the base load.	Load profile analysis with load r
WH Nominal Usage by Sizes	Yearly average usage of electricity of water heaters of different sizes.	Estimate
Salary Full Time	Standard unit of NSP full time salary	Estimate
DRMS Platform Cost	The platform responsible for communication, monitoring, control and administrate the DR program	Estimate
Marketing Cost	Cost to promote program and products, and recruit and educate customers	Estimated
Program Management Cost	Internal cost for program administration and deployment of new operation	Estimated

Assumptions

Parameter	Description	Assumption and Justification	Estimate
Year to Implement	The first year to roll out the program. Funding and resouces are allocated. Vendors and partners are determined. Regulatory approval should also be obtained.	Timeline for program development.	2022
Battery ownership	One of the following: 1. customer owned batteries (through utility rebate or ongoing incentive program) 2. finance to own batteries 3. NSP owned	Customers shall own the batteries in agreement to participate DR program and receive rebate as an incentive (we don't believe there are existing battery homes so excluded ongoing incentive into consideration). Customers could either pay upfront or finance towards the customer contribution amount. Not in scope: NSP would not own BTM batteries. Finance would be an option similar to WH/HP programs, but will require a separate program design.	Customer Own
Battery target customer sector	All Electric residential homes	AE home load profile will be provided for simulation with the assumption of whole home back up for 4 hours	All Electric homes
Residential battery adoption by manufactures	The market demand for various battery makes and types.	Use average of Lithium-ion bottom two for cost	Generic battery specification
Battery prices ($)	Typcial prices of battery hardware systems including installation costs	based on quotes from previous experience.	$15,000.00
Installation Discount due to quantity	To account for the reduced cost if installation due to quantity discount if there is any.	it is applicable including in the total battery price	
Battery usable capacity (kWh)	battery usable size	average of two available batteries 7.4kWh and 13.5kWh	10.45
Battery Peak Shaving (kW)	Battery discharge power	Based on 4 hour period DR event, Two potential batteries have DR capacity 1.85 kW (7.4/4), and 3.3 kW (13.5/4). On average, the peak reduction esitmate is 2.5 kW	2.5
Battery uptake estimate (unit/year)	Total number of batteries need to be adopted and their distribution among manufacturers	Target 0.5 MW/year for connected battery capacity, which is 200 battery units.	200
Program timeline (years)	from 1 up to 25 years. years to grow the capacity based on the uptake rate	NSP will target a total of 10 MW battery resource. For example, Great Mountain Power aims 2000 units for 2 hour duration per DR event which adds up to the same capacity	20
Battery lifespan (cycles) deterioration rate	maximum cycles the battery can be operated	Both potential batteries have warranty of 10 years unlimited cycle. Battery life will depend on usage. For IRP, a deterioration rate of 50% after 10 years.	unlimited up to 10 years 50% after 10 years
Customer contribution ($)		Comparable to the customer purchase of diesel generator for reliability, plus the difference in fuel cost and other operation and maintenance values.	2500
DERMS assumption: additional capacity connected ($/kW)		Based on the quote from available DERMS options for engineering service.	13
DERMS assumption: additional asset ($/asset)		Based on available quotes. NTD: when using one aggregator for batteries, it is equivalent to one asset.	5000
Aggregator SaaS service charge ($/year)		Based on quotes	20000

Assumptions

Parameter	Description	Assumption and Justification	Estimate
Year to Implement	The first year to roll out the program.	Timeline for program development.	2022
EV charger price	charger cost and associated upgrade		Based on quotes $1250 for chargepoint smart charger on high side. $754 installation plus possible electrical upgrade
EV charger purchase rebate ($)	customer owned charger (through utility rebate and/or ongoing incentive program)	$350 to compensate the difference between smart and non-smart level 2 charger. Technology trends show the price difference between smart and non-smart chargers are insignificant.	0
EV charger Average Peak Contribution (kW)	Coincident peak of unit charger	Based on 2019 load forecasting report.	1.3
EV charger peak shaving potential (kW)	Peak shifting capability based on load	Based on 2019 load forecasting report.	0.7
One-time enrollment incentive ($)	Jurisdication Scan: - Eversource's connected solutions EV charger program - GMP pays no sign up incentive for BYOD.	We propose eversource model using $150 as the one-time incentive for enrollment.	150
On-going incentive ($/year)	Jurisdictional scan: - Eversouce's connected solutions program $50 per year ongoing - Ohio $5 monthly credit. - SDGE uses TOU as an incentive. - smart charge NY fleet karma uses TOU and program rewards - GMP $10 monthly bill credit.	We propose $50 per year as the initial rate, and gauge it during IRP simulation. this rate is also same as the 2014 IRP.	50
EV DR uptake estimate per year	percentage of the total Evs on road	Load forecasting assumes there are some peak mitigation mechanisms for each charger. We could further assume 70% of the peak mitigation will be resulted from DR program	70
DR program duration (years)		We intend to include all Evs in the DR program	25
DERMS assumption: additional capacity connected ($/kW)		Based on available quotes	3
DERMS assumption: additional asset ($/asset)		Based on available quotes. NTD: when using aggregator, this number is not necessarily the number of end use appliances.	13
Aggregator SaaS service ($/year)		Based on available quotes	20000