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Request IR-1:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 5 [Lines 22-24] states: "The changes underway in our electricity system make good sense for all sorts of reasons. Without them, Nova Scotia would be headed for an unsustainable future – a future of much higher energy costs, uncompetitive industry, and environmental harm.

a) Please indicate what studies NSPI has undertaken or obtained 1 which show that there will be "much higher energy costs" in the future.

b) Please provide a copy of any such studies in NSPI's possession.

c) Does this statement imply that as a result of the "changes underway" that electricity costs will be lower in the future?

d) If the answer to (c) is "No" please explain why.

Response IR-1:

(a-d) NS Power is undergoing a transformation that will increase renewable energy production and, through energy efficiency programs, delay the requirement for new, baseload generation. This transformation was confirmed by the 2009 Integrated Resource Plan (IRP) Update to be the low-cost solution for our customers.[1] NS Power accepts the 2009 IRP Update that indicates electricity costs will be lower in the future as a result of the transformation than under any other reasonable plan. Absent changes to our business, customers would be facing higher energy costs and higher emissions which would harm both industry and our environment.

---

[1] NSPI 2009 Integrated Resource Plan Update, NSUARB-NSPI-P-884, November 30, 2009.

Request IR-2:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 5 [Lines 25-26] states: "…we are convinced that sticking with imported, high-carbon fuels now would ensure far greater problems down the road."

a) Please further explain this statement.

b) Please provide some examples of the "far greater problems".

Response IR-2:

(a-b) Please refer to Avon IR-1. NS Power's planning activities and consultations with stakeholders, including the Integrated Resource Plan (IRP) processes, have shown that the best options for keeping costs as low as possible for our customers while complying with environmental laws is to conserve energy and increase renewable generation. This is the lowest cost option for the future of electricity in Nova Scotia. For example, acting now on the "no regrets" strategy from the IRP[1] has helped the Company achieve an equivalency agreement with the Federal Government on coal plant closure, which saves money for customers by enabling those plants to be used until the end of their economic lives rather than a regulated number of years.

---

[1] NSPI 2009 Integrated Resource Plan Update, NSUARB-NSPI-P-884, November 30, 2009.

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Request IR-3:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04, pdf Page 6/159, Line 8. Please provide NSPI's estimates of the various components of the "rate pressure coming for the next few years

Response IR-3:

NS Power has indicated, on several occasions, to Intervenors and the broader public that rate pressure will continue over the next several years. In 2011, the Company proposed a multi-year rate plan to stabilize rates at 4 percent per year for 2012, 2013 and 2014. As part of our presentations to stakeholders, NS Power included an overview of cost pressures out to 2015 that shows estimates of the various components. Please refer to Attachment 1. NS Power has also made Intervenors and the broader public aware that the two year rate stabilization plan defers the loss from load impact to rates out to 2015. The loss of load from the pulp and paper industry adds additional pressure to rates. For 2015, the key rate pressures are anticipated to be related to increased fuel costs, recovery of additional capital, increased income tax expense and loss of load.

NSPI
Cost Pressures and Electricity Rates
Stakeholder Dialogue

April 20, 2011

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NOVA SCOTIA POWER
An Emera Company

Agenda – April 20, 2011

1. Customer Rates Overview

2. 2012 by the numbers

3. Where are costs headed?

3. The path forward

Caution Regarding Forward-Looking Information For NSPI

Information contained in this presentation by Nova Scotia Power Inc., including but not limited to information about future costs, sales and revenue, includes forward-looking information reflecting management's expectations regarding the Company's future operation, performance and financial results. It should not be read as a guarantee of future performance or results, and will not necessarily be an accurate indication of whether, or the times at which, such performance or results will be achieved. Forward looking information is based on a variety of assumptions, and is not a guarantee of future performance or results. Forward looking information is subject to risks, uncertainties and other factors that could cause actual results to be materially different from the information presented. Additional information about NSPI's risk factors can be found in the Company's annual information form filed on SEDAR at www.sedar.com.

Customer Rates - Overview

- Nova Scotia Power collects UARB approved costs required to serve customers

- There are 2 distinct components to current rates
  - General rates – reflect all costs of service
  - Fuel Adjustment Mechanism – reflect Base Cost of Fuel (BCF), Annual Adjustment (AA) and Balancing Adjustment (BA)

- Through their power bills, customers also pay
  - Efficiency NS DSM charge – reflects conservation and efficiency costs
  - The 5% federal portion of the HST

- NSPI actively manages all of its costs to keep rates low.

NSPI – Transformation

- NS Power is undergoing a period of historic change
  - We’re investing more in Nova Scotia
  - Our energy is getting cleaner and greener
  - We are still vulnerable to volatile global fuel prices
- This change is carefully planned and actively managed
  - EGSPA goals provide an enabling framework
  - An Integrated Resource Plan has identified the most cost-effective path forward
  - The path forward is regularly updated and optimized
- Increased investment in clean, local energy benefits Nova Scotia
  - We’re helping achieve the goals that are important to Nova Scotians – a cleaner environment, better energy security and driving local investments that help create jobs
  - By 2020 we will have significantly reduced our exposure to fossil fuel prices
- Examples
  - Nuttby Mountain, Digby, Pt. Tupper Wind, Port Hawkesbury Biomass Projects
  - TUC 6 Waste Heat Recovery. Mercury Abatement, TRE Baghouse
  - Upcoming – LED Streetlights, Hydro Upgrades, new renewables

How general rates are set in Nova Scotia

- Like most companies NS Power measures and analyzes its business plan against actual results
- Each year we determine whether a rate application may be necessary in order that revenues will recover the costs of service
- An application to change general rates must usually be filed in May in order to complete all elements of the hearing process by year end
- All changes to customer rates require UARB approval
- Recent processes (FAM, Depreciation) have demonstrated there are ways to manage cost recovery for customers and for the utility

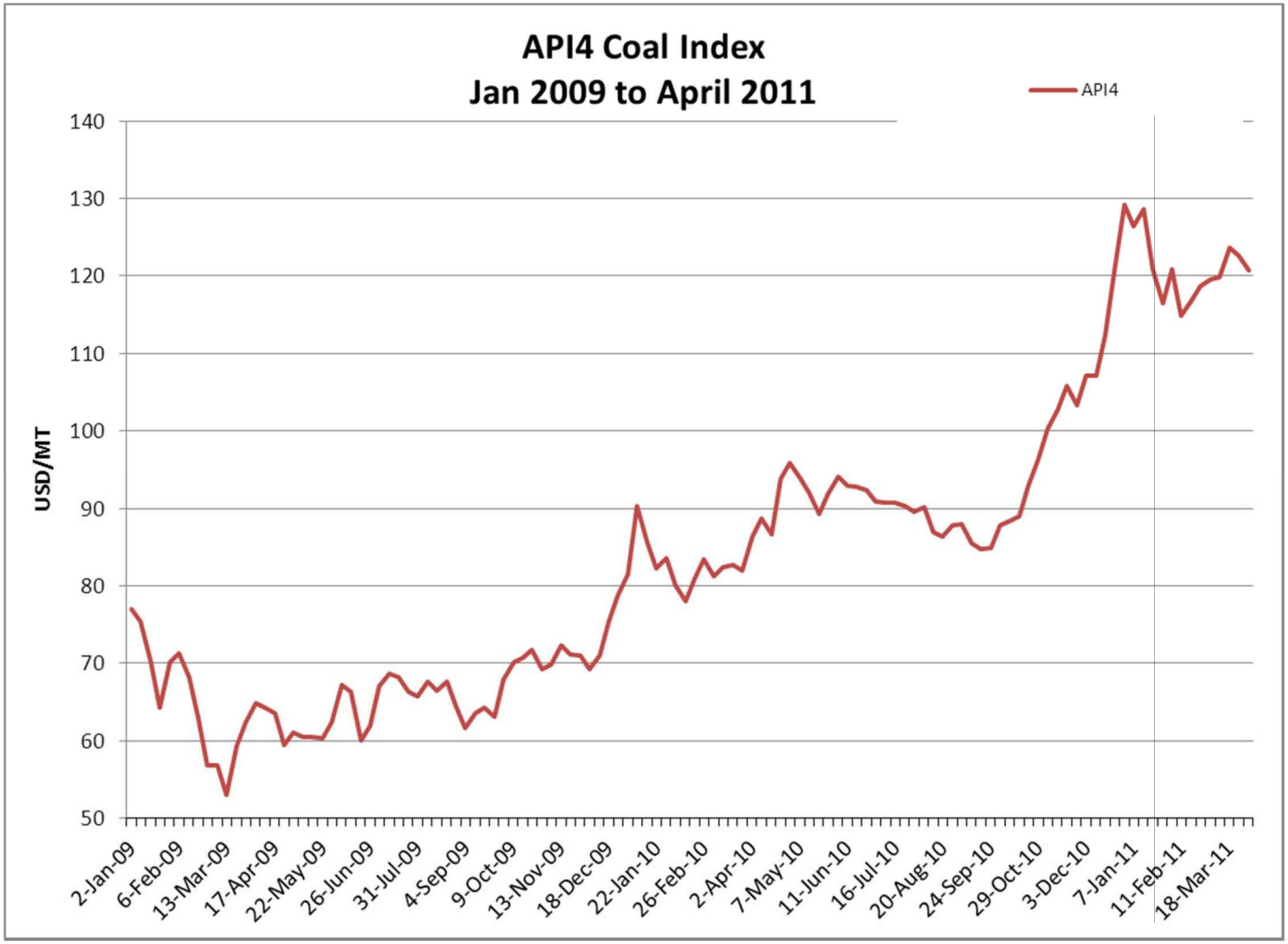
2012 By the Numbers

2012 Load Forecast *rel: 04-Jan-2011*

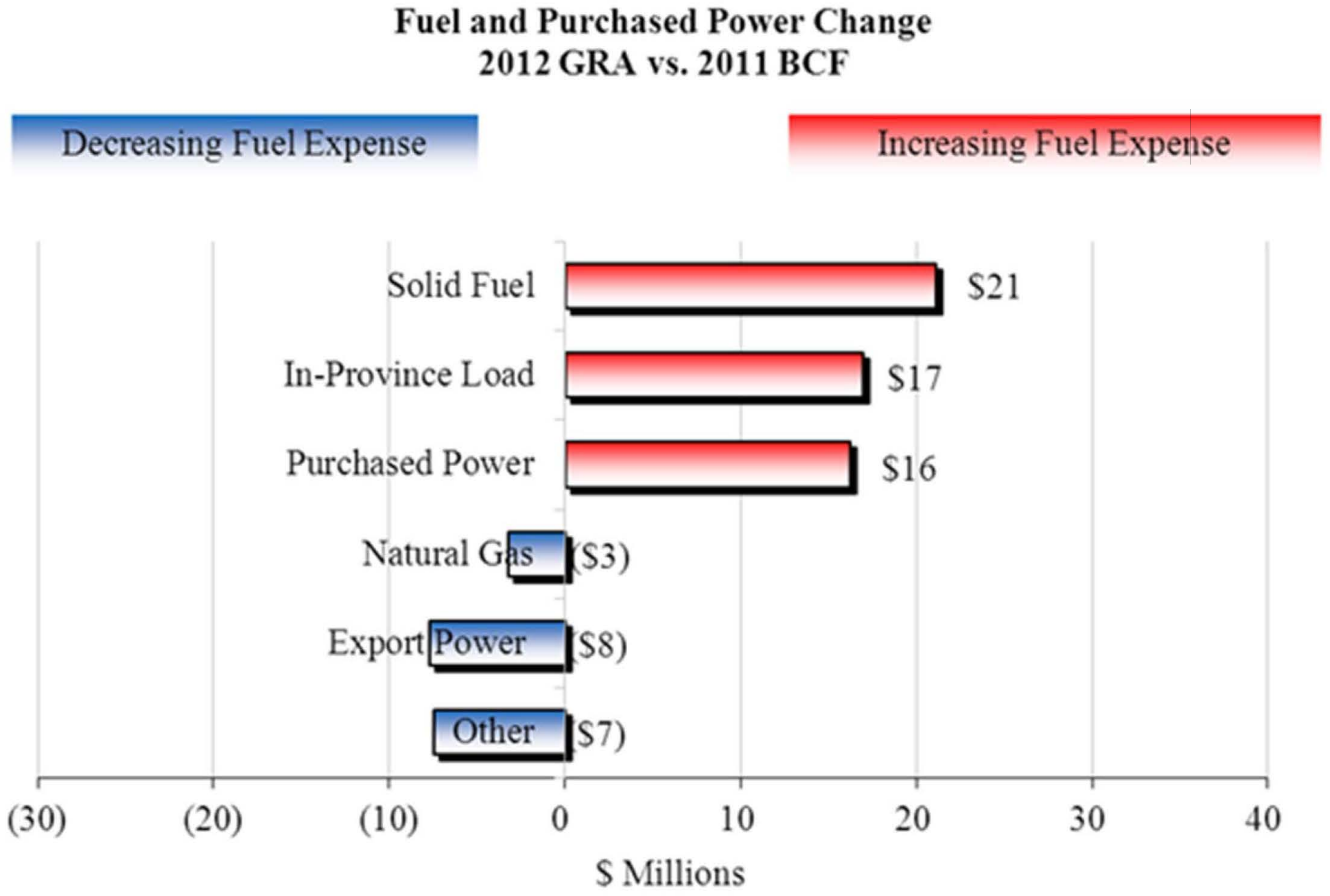
- Includes effective 301.5 GWh & 59.3 MW DSM effects, from 2011-2012 programs
- Conference Board of Canada economic forecast 28-Oct-10
- based on 2010 load projection as of Nov-2010
- LED Street Light Program 4.45 GWh reduction

Month	NSR GWh	Annual GWh	System Peak MW	Coincident Interruptible Peak MW	Coincident Firm Peak MW
Jan-12	1,293.8		2308.4	308.5	1999.9
Feb-12	1,168.6		2291.2	313.7	1977.6
Mar-12	1,197.7		2033.4	306.1	1727.3
Apr-12	1,035.7		1839.7	298.7	1541.1
May-12	989.1		1630.1	313.5	1316.6
Jun-12	910.9		1501.5	315.1	1186.5
Jul-12	946.3		1590.6	315.0	1275.6
Aug-12	951.5		1585.2	351.7	1233.5
Sep-12	910.5		1498.0	332.7	1165.3
Oct-12	972.8		1645.0	322.0	1323.0
Nov-12	1,035.9		1880.5	336.3	1544.2
Dec-12	1,234.5	12,647.1	2232.1	313.6	1918.5

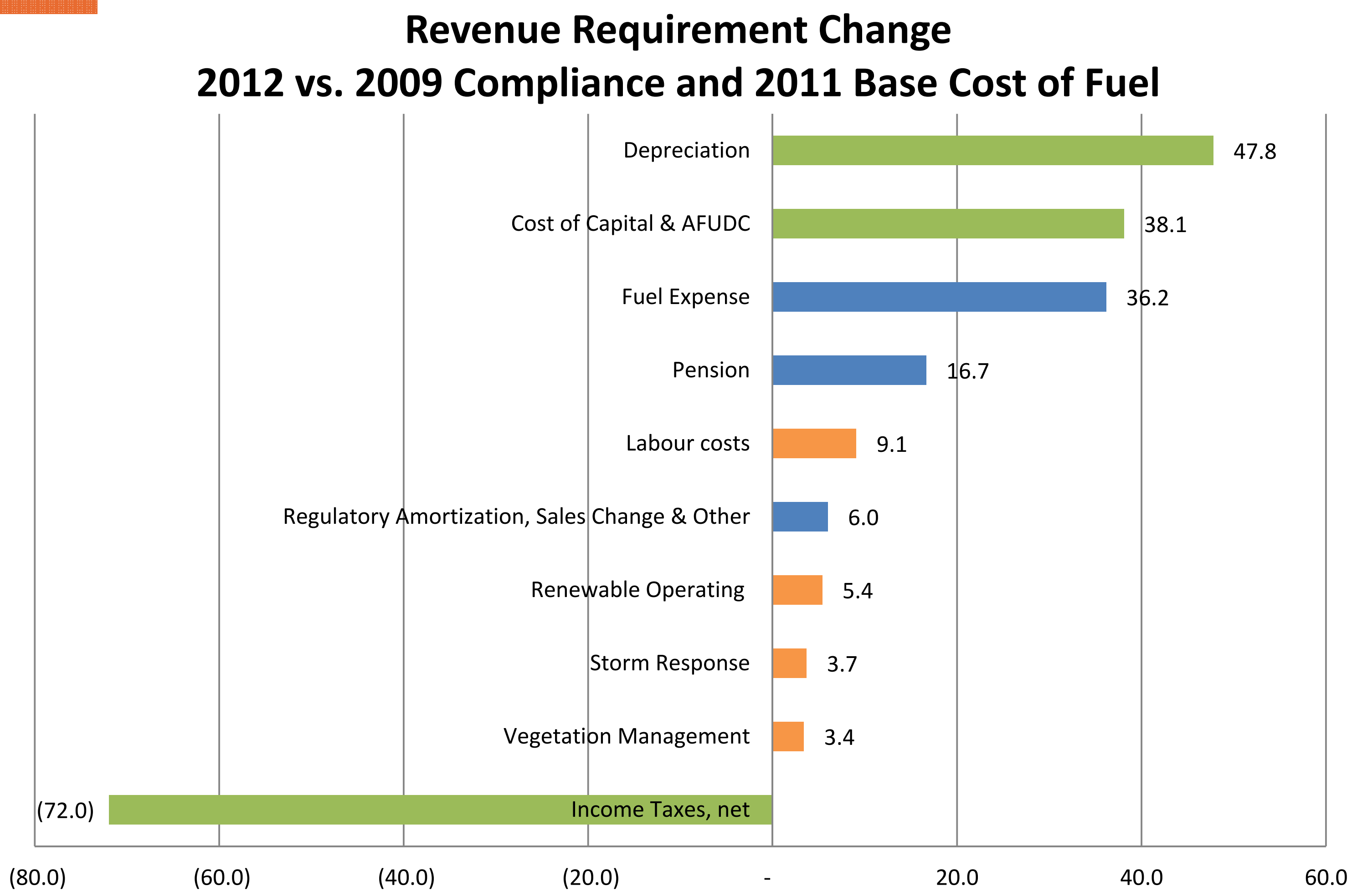
Coal Prices – volatile and rising



2012 By the Numbers



2012 By the Numbers



Revenue components are tax effected to demonstrate full rate effect

2012 By the Numbers

Customer Class	General Rates	After FAM and ENSC Charges
Residential	7.1%	8.8%
Avg Commercial	6.1%	7.4%
Avg Industrial	10.0%	13.5%
2P-RTP	13.5%	16.8%
Municipal	7.02%	9.1%
Average ATL	7.3%	9.2%

Where are costs headed?

Outlook for 2013, 2014 and 2015

- NS Power has produced an outlook of likely costs for business planning purposes
- Given the magnitude of change underway we want to share these with stakeholders to ensure they have the same level of information we do to plan for coming years
- This information can provide a useful starting point for dialogue

Outlook for 2013, 2014 and 2015

	2012	**2013**	**2014**	**2015**
Fuel expense	574	591	604	628
FAM fuel adjustment	50	23	0	0
OM&G (incl pension)	256	263	267	272
Depreciation (not tax effected)	178	190	202	211
Taxes – current	29	24	-5	-2
Avg Rate Increase (rounded)	9%	4%	2%	5%
Year end capitalization	3,713	3,965	4,265	4,473
Revenue Requirement (in millions)	1,388	1,426	1,431	1,483
Net System Requirement (GWh)	12,647	12,507	12,339	12,180

Note – Refer to the caution regarding forward-looking information for NSPI at the beginning of this presentation. These figures are estimates, not forecasts, and are subject to change at the time of future applications or in reporting of results. Please consult NSPI for current information.

The path forward

Alternatives and next steps

- NS Power would like your input and a continued dialogue
- Another meeting to discuss options and alternatives would be helpful
- What additional information would be required
- Timing and schedule for dialogue

Questions?

Please contact NSPI Regulatory Affairs at any time if you have questions or input

Thank you for attending

Request IR-4:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 7 [Line 1] states: "We are actively seeking ways to reduce fixed costs as the load on our system decreases."

a) Does NSPI agree that wind generation is characterized by high fixed and low variable costs? If so, please explain how further additions of wind generation to the NSPI system is consistent with the above statement.

b) Please indicate in detail the ways in which NSPI is seeking to reduce fixed costs.

Response IR-4:

(a) Yes. NS Power will seek to add further wind generation if necessary to comply with Renewable Electricity Standard (RES) or greenhouse gas reduction requirements.

(b) Please refer to Liberty IR-34 for ways NS Power is seeking to reduce fixed costs.

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Request IR-5:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04, pdf Page 7/159, Lines 19-21:

a) Please provide the calculations of the "incremental 1 or 2 percent per year" impact on rates, breaking down the cost components.

b) Please indicate for how many years NSPI projects such 1 or 2 percent per year increases.

c) Has NSPI performed or had performed any studies or analyses to support this 1 or 2 percent estimate? If so, please provide copies of all such studies or analyses.

Response IR-5:

(a-c) Please refer to Attachment 1.

Incremental Cost of Renewables (prepared October 2011)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Renewables Revenue Requirement ($ in millions)	0.2	5.6	6.0	9.8	9.1	9.4	4.5	40.8	60.8	117.9	144.8
Renewable Generation (GWh)	4.4	83.1	109.5	160.6	147.6	150.2	379.6	781.0	904.4	1,265.8	1,579.8
Total Avoided Cost ($ in millions)	0.1	2.9	3.6	6.0	5.8	6.6	19.3	38.5	43.3	65.1	86.7
Incremental Cost of Renewables ($ in millions)	0.1	2.7	2.5	3.8	3.4	2.7	(14.8)	2.3	17.5	52.8	58.1
Total Incremental Cost of Renewables to 2014 ($ in millions)											58.1
Base Revenue for Present Rates ($ in millions)											1,294.7
Total Rate Impact											4.49%
Average 3-Year Rate Impact											1.50%

Request IR-6:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 8 [Lines 5-6] states: "Our coal use may fluctuate in the short term as we constantly seek the best energy value, but the long-term trend will continue downward."

a) Please indicate the expected future closure dates for redundant NSPI coal units.

b) Please indicate what studies have been done on the anticipated closure of redundant coal units. Please provide copies of such studies.

Response IR-6:

(a) NS Power does not have identified closure dates for its solid fuel generation units, nor are any considered to be redundant. The Federal Government has introduced regulations that require coal generation units to be closed at 45 years of age. Under the principle of equivalency, NS Power will have the flexibility to determine the appropriate retirement date, on economic grounds, for specific units. For depreciation purposes, NS Power has identified the date that each unit entered into service, as follows:

- Trenton 5 – 1969
- Trenton 6 – 1991
- Lingan 1 – 1979
- Lingan 2 – 1980
- Lingan 3 – 1983
- Lingan 4 – 1984
- Point Tupper – 1973 (Coal conversion in 1987)
- Point Aconi – 1994

Please also refer to Multeese IR-7.

(b) NS Power conducted a study in the fall and winter of 2011 to provide insight into the operation of the generation facilities in light of decreased energy demand. It is entitled "Power Production Transformation Strategy". Please refer to Attachment 1. The primary recommendation from the analysis was to seasonally operate Lingan Units 1 and 2. The seasonal operation plan provides maximum unit flexibility and reliability during peak months of the year while reducing the plant's overall non-fuel expense. Seasonal operation also limits exposure to high replacement energy cost during the winter peak load months. This option was assessed to provide the best value for customers.

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Power Production Transformation Strategy

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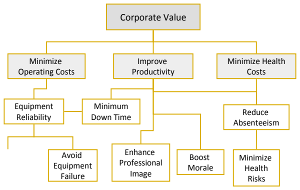
A structured approach to improve decision quality.

Making the Choice

Making it Work

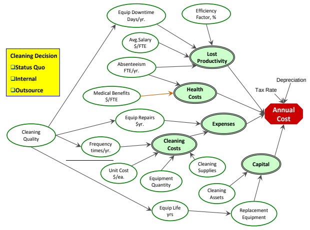
What is it that we need to decide and why?



- *What is the opportunity?*
- *Who needs to be involved?*
- *What are we aiming for?*

Study It?

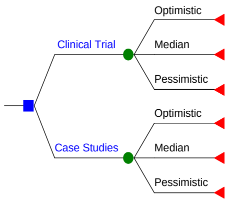
What choices are open to us and how should we compare them?



- *What are the decision criteria?*
- *What alternatives should we compare?*
- *How should we compare them?*
- *Who should assess the uncertainty?*

Analyze It?

Which choice do we prefer?



- *What are the ranges of uncertainty?*
- *Is there value of information/control?*
- *What is our preferred path forward?*

Finish It?

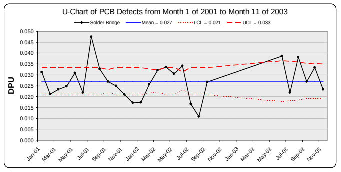
What do we need to do to translate our choice into action?

WHAT▼ WHO►	Assistant	Chief	PM	IT	User
Scheduling	R	A	C		I
Materials	S	A, S	R	S	
Training	R		A, C		
Deployment	R		I	S	I
Monitoring	R		A, C		
Safety	I	A	R		
Record Keeping	R	I	A		

- *What resources must we commit?*
- *What indicators are important?*
- *What's the schedule?*
- *How can we manage risks?*

Fund It?

Are we on the right course in the right way?


U-Chart of PCB Defects from Month 1 of 2001 to Month 11 of 2003

- *How do we manage change?*
- *What can we improve?*
- *What should we do in light of unfolding events?*

Lead It

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Situation

- On August 22nd, NewPage announced the indefinite closure of its Port Hawkesbury mill. The company subsequently applied for and received protection from creditors for a period of time to allow for the potential sale of the plant
- The NewPage mill accounts for approximately 13% of system total, ranging from 11% in the winter months to 14% in low system load months
- NSPI has been asked by the UARB to file a plan to minimize the impact of the closure on our customers
- Following the NewPage announcement, Resolute Forest Products announced the potential indefinite closure of Bowater Mersey Paper Company

Governance & Participants

Governance (Decision Board)

NSPI ELT

- Rob Bennett
- Mark Sidebottom
- Mark Savory
- David Landrigan
- Rene Gallant
- Claudette Porter
- Barb Meens-Thistle
- Robin McAdam

Project Team

- Exec. Sponsor – Mark Sidebottom
- Project Lead – James Taylor
- DA Consultant – Nick Martino
- Modeler – Dragan Pecurica, Craig DeGier
- Sr. Technical Advisor - Rob MacNeil
- Business Manager, Power Production - Joan MacDonald
- Sr. Plant Mgr. Tufts Cove – Dave Pickles
- Plant Manager, Trenton – Jamie MacDonald
- Human Resources - James McKee
- Manager of Plant Performance - Barrie Fiolek
- Control Center/Systems Ops – James Delorme/Paul Casey
- Fuels Group – Sean MacPherson

Subject Matter Experts (SMEs) – interviewed to assess ranges of uncertainty

- Mike Sampson
- Allison Donnelly
- Generation Asset Experts
- Brad George
- Robin McAdam
- Marie Thomas
- System Operations Experts

Project Charter – Mission & Objectives

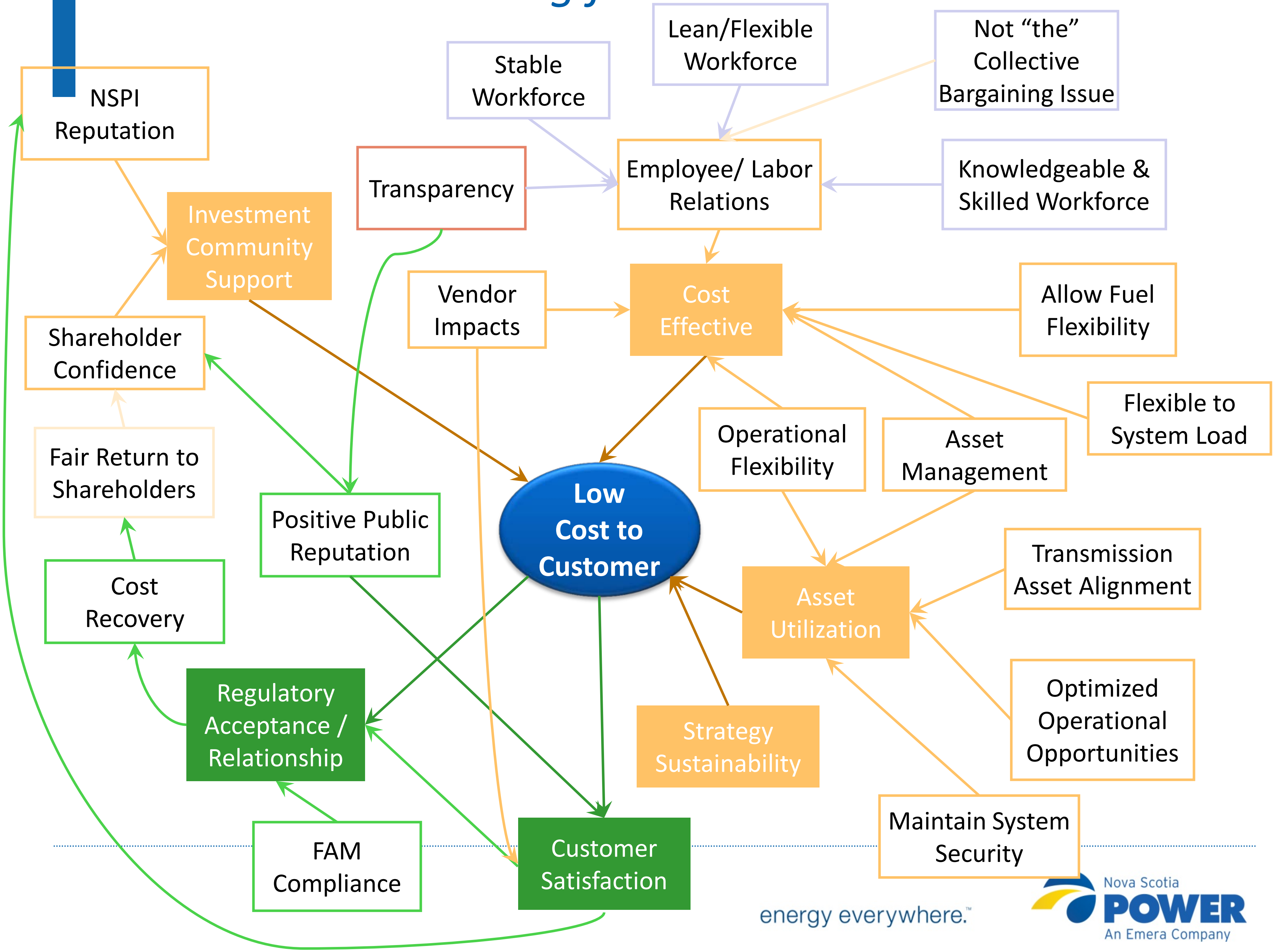
Project Mission Statement

Deliver a plan that in the absence of the NewPage and/or Bowater load will define how to run and manage generating assets to maximize value for our customers.

Project Objectives

1	Determine the lowest cost approach to generation dispatch (e.g. idling a single unit vs. longer, low intensity unit maintenance outages)
2	Define fuel cost ramifications for customers
3	Understand the directional change in asset management (i.e. Capital Planning, Outage Planning, Maintenance Strategy) for the generating units to 2020
4	Define impact to Renewable Electricity Standard Compliance Plan, the Renewable Energy Integration Study, and the Emissions Compliance Plan
5	Define impact on system operations (reserve, transmission bottlenecks, etc.)
6	Develop a range of “readiness” scenarios for the potential return to service of the NewPage plant and associated costs.
7	Define organizational impacts (increased organizational flexibility, balance re reducing costs in the shorter term vs retention of the right skills that are needed for the future)

What are we aiming for?



Lean/Flexible Workforce

Not "the" Collective Bargaining Issue

Stable Workforce

NSPI Reputation

Transparency

Employee/ Labor Relations

Knowledgeable & Skilled Workforce

Investment Community Support

Vendor Impacts

Cost Effective

Allow Fuel Flexibility

Shareholder Confidence

Flexible to System Load

Operational Flexibility

Asset Management

Fair Return to Shareholders

Positive Public Reputation

Low Cost to Customer

Transmission Asset Alignment

Cost Recovery

Asset Utilization

Regulatory Acceptance / Relationship

Optimized Operational Opportunities

Strategy Sustainability

Maintain System Security

FAM Compliance

Customer Satisfaction

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What is the menu of potential strategic options?

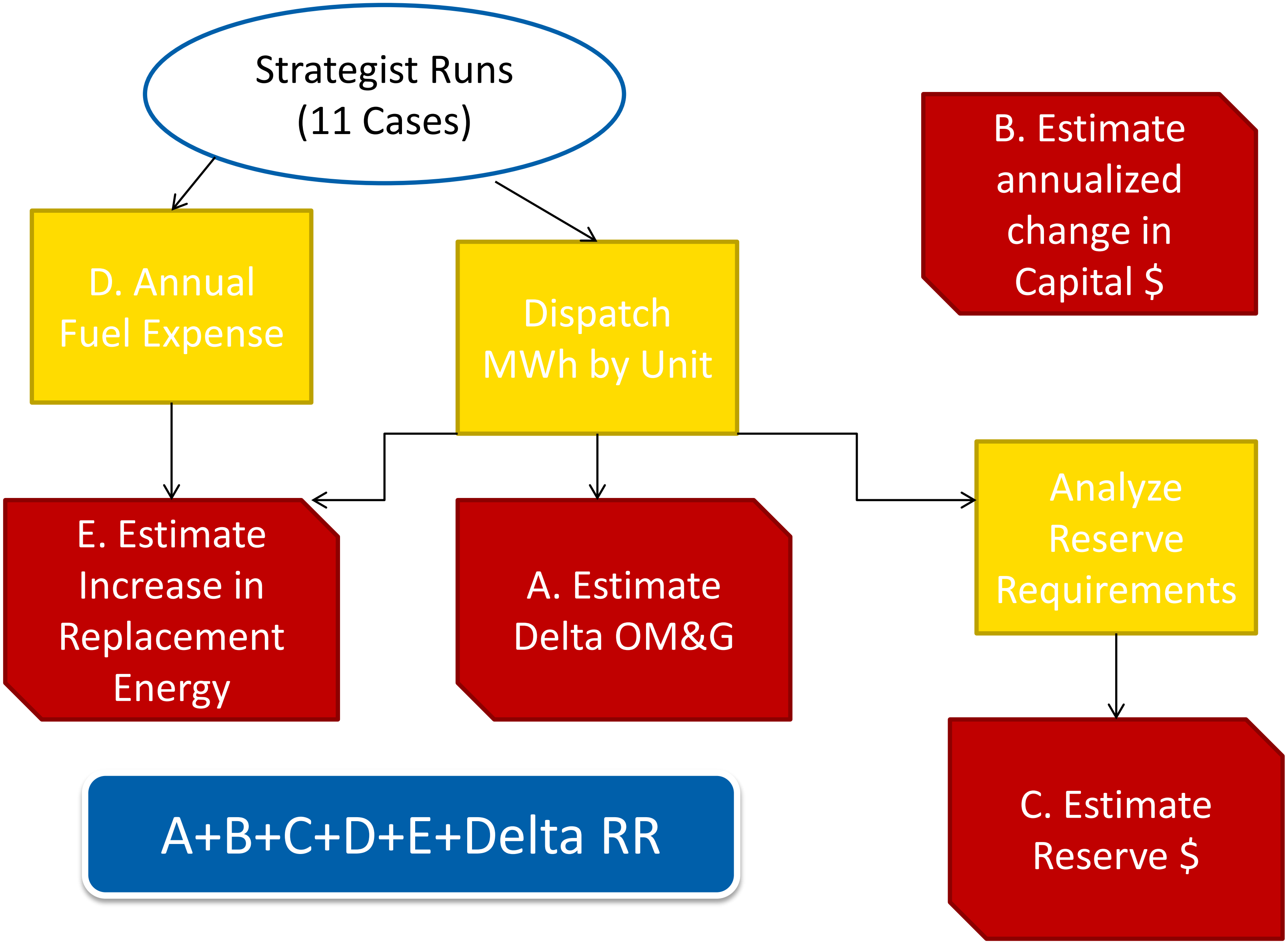
Menu of Strategic Decisions				
Open Decisions				
Gas Conversions	Reserve Management	Retirement Strategy	Import Generation to 2017	Low CV Solid Fuel Flexibility
Yes	Install Add'l Fast Acting Generation	Economic Choice from Strategist	150 MW	Yes
No	Meter Large Industrials & Breaker Control	Accelerate One Unit	50 MW	No
	Buy Non-Firm Energy or Breaker Industrials	Accelerate Two Units	Short Term Opportunistic	
	Interrupt Interruptable Customers More Often	Multi-unit Station Closure		
	Burn Oil / Redispatch Fleet (e.g, utlize Hydro)	Single-unit Station Closure		
	No action required (maintain % of non-firm sales)	Regulated Retirements Only		

Strategist Dispatch Optimization Scenario/Case Matrix – (Version 2)

Strategy Themes	Loss of NP and BW	Loss of NP	Loss of BW or NP PM1	No loss of industrial load
Momentum	No*	No*	No	Yes
Seasonal Operation Of 1 (2) Units	Yes	Yes	No	No
Shut Down 1 (2) Units Advance Fast-Acting Generation	Yes	Yes	Maybe	No
Solid Fuel Switching Derate	Yes	Yes	Yes	Maybe

NOTE:
- Fuel Pricing is per the IRP Base Case Refresh
- Load is 2012 GRA refresh load forecast (the most recent load forecast)
- DSM is ENSC Base Case DSM as of Oct 2011

Block Diagram of Analysis



Strategist Runs
(11 Cases)

D. Annual Fuel Expense

Dispatch MWh by Unit

B. Estimate annualized change in Capital $

E. Estimate Increase in Replacement Energy

A. Estimate Delta OM&G

Analyze Reserve Requirements

C. Estimate Reserve $

A+B+C+D+E+Delta RR

Cases

1 BASE WITH ALL SALES IN TACT AND ALL UNITS AVAILABLE

2 NPPH LOST AND ONE UNIT AT LINGAN SEASONAL OPERATION

5 NPPH LOST AND TWO UNITS AT LINGAN SEASONAL OPERATION

9 NPPH LOST AND TWO UNITS AT LINGAN SEASONAL OPERATION AND TWO UNITS AT LINGAN RETIRED IN 2015 AND PRB COAL USE MAXIMIZED

3 NPPH + BW LOST AND ONE UNIT AT LINGAN SEASONAL OPERATION

4 NPPH + BW LOST AND TWO UNITS AT LINGAN RETIRED

6 NPPH + BW LOST AND TWO UNITS AT LINGAN SEASONAL OPERATION

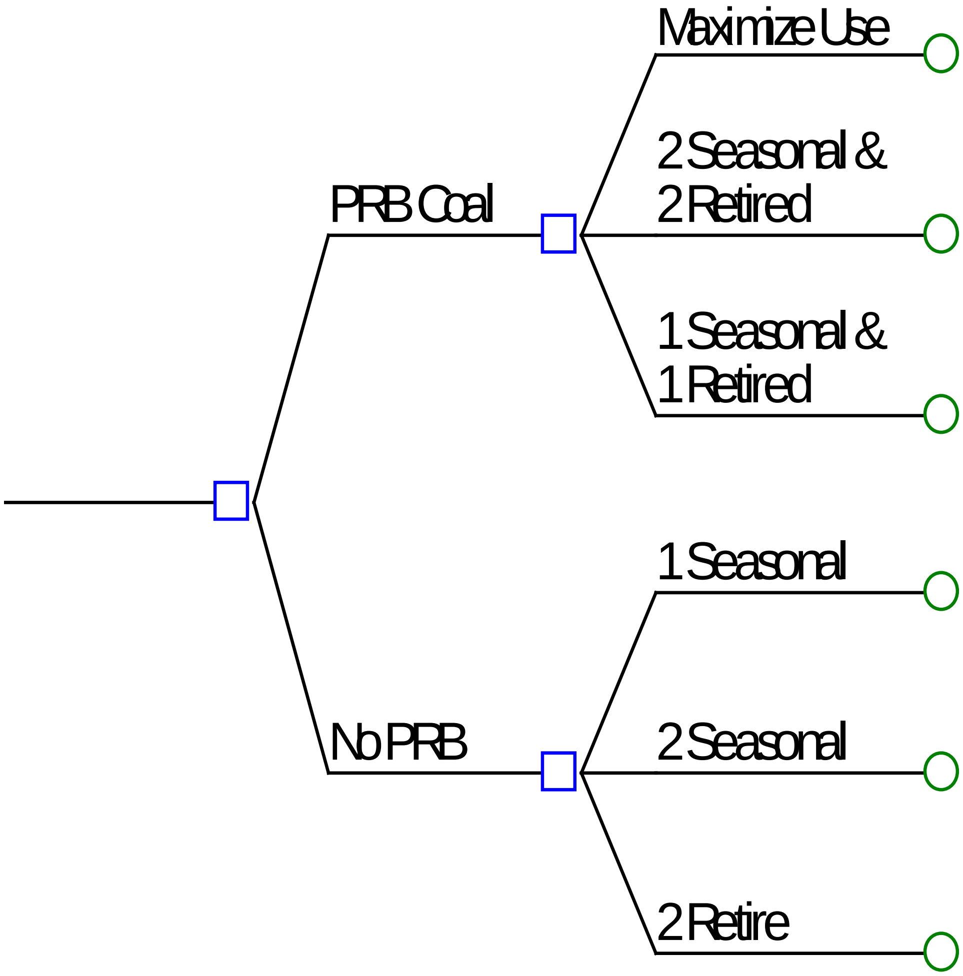
7 NPPH + BW LOST AND PRB COAL USE MAXIMIZED

8 NPPH + BW LOST AND TWO UNITS AT LINGAN SEASONAL OPERATION AND TWO UNITS AT LINGAN RETIRED IN 2015 AND PRB COAL USE MAXIMIZED

10 NPPH + BW LOST AND ONE UNIT AT LINGAN SEASONAL OPERATION AND ONE UNIT RETIRED IN 2013 AND PRB COAL USE MAXIMIZED

11 NPPH LOST AND ONE UNIT AT LINGAN SEASONAL OPERATION AND ONE UNIT RETIRED IN 2013 AND PRB COAL USE MAXIMIZED

Strategist Dispatch Optimization
Matrix of Scenarios Analyzed



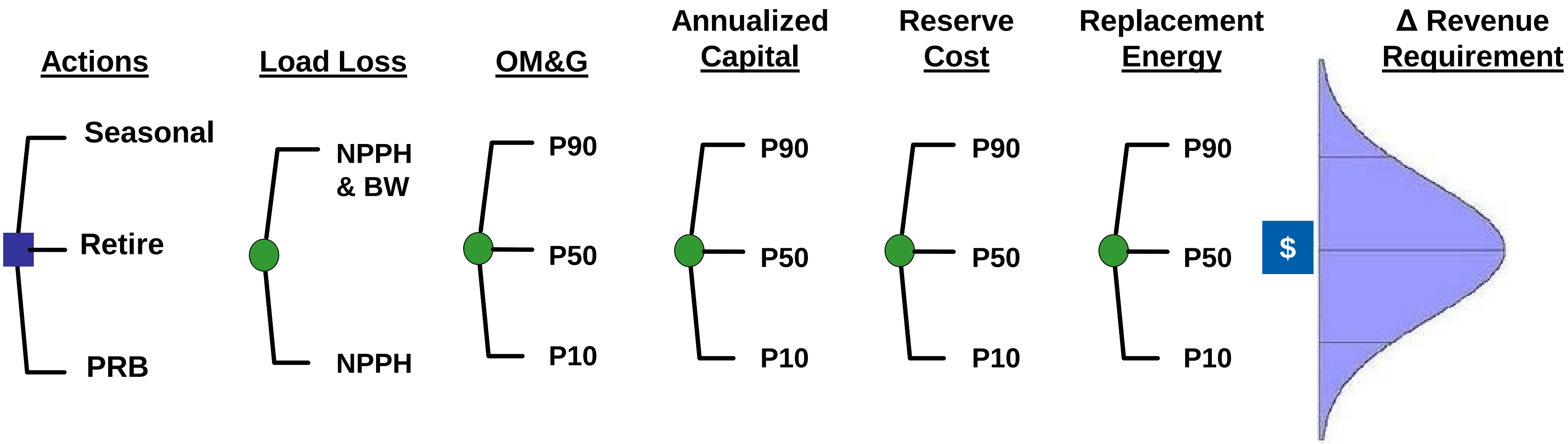
Loss of NPPH & BW	Loss of NPPH
Scenario 7	
Scenario 8	Scenario 9
Scenario 10	Scenario 11
Scenario 3	Scenario 2
Scenario 6	Scenario 5
Scenario 4	

NOTE:
- Fuel Pricing is per the IRP Base Case Refresh
- Load is 2012 GRA refresh load forecast (the most recent load forecast)
- DSM is ENSC Base Case DSM as of Oct 2011

Description of Alternatives

Action	Description	Objective/Rationale
Seasonal	Operate one or two units seasonally and lay them up with a 10-day return. (Different from practice at TUC1.)	• Save OM&G expense by reducing planned outages and redeploying staff to reduce operator OT. • Save variable production costs such as water and chemicals. • Improve "average" heat rate by keeping remaining units at higher load.
Retire	Shut down one or two units and advance installation of Fast-Acting Generation for Capacity/Reserve if required	Same as "Seasonal" strategy; save money.
PRB	Lower heating value fuels equal low MW and run selected units at lower CF, perhaps seasonally. Apply to 5 units.	Lower fuel costs even with a derating in output.

Schematic of analysis



Actions

- Seasonal
- Retire
- PRB

Load Loss

- NPPH & BW
- NPPH

OM&G

- P90
- P50
- P10

Annualized Capital

- P90
- P50
- P10

Reserve Cost

- P90
- P50
- P10

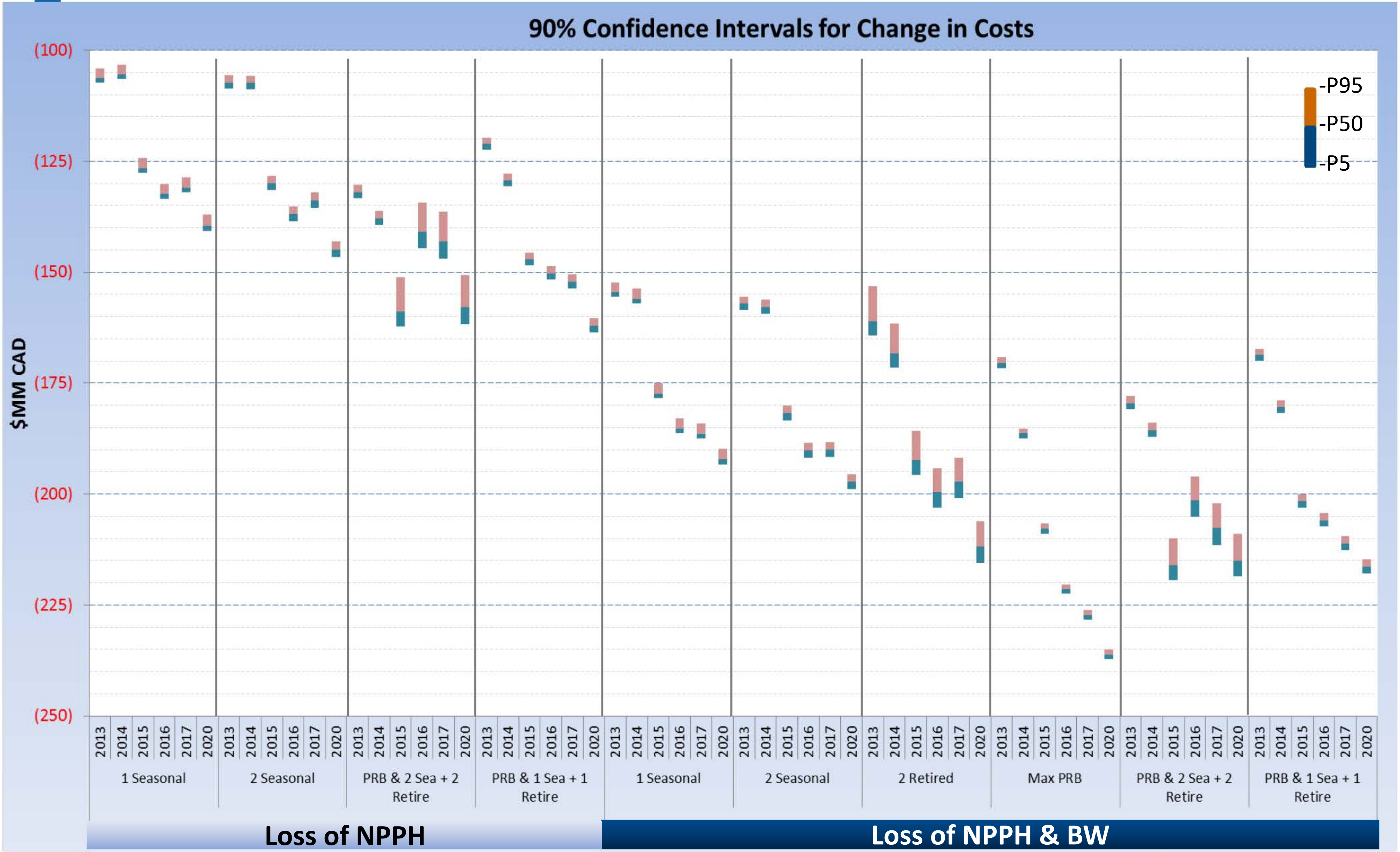
Replacement Energy

- P90
- P50
- P10

$

Δ Revenue Requirement

Delta Costs generally decline over time compared with the Base Case. Greater uncertainty with Retirement and Max PRB.



Qualitative Summary

Strategic Alternatives -------------------------------- Qualitative Attributes	Momentum	Seasonal Operation	Shut Down Unit(s)	Solid Fuel Switching Derate
Customers/Regulator				
Environment Reduces Non-fuel Revenue Rqmt	🟥 Does not address expectation of UARB	🟨 No environmental impact Can plan marginal operational savings	🟩 Reduces non-fuel revenue rqmt	🟨 Low AP but no Non-Fuel RR reduction but may help Reserve Requirements
FAM - Fuel Cost				
Price Stability/Predictability	🟩 Flexibility in response to price volatility	🟨 Can run coal in winter rather than purchase high priced power	🟥 Exposes customer to high replacement energy costs	🟩 Low cost fuel. Extra costs on fuel handling. Some risk of achieving.
Employees				
Employment Security Transfer Pride in Operation	🟩 Preserves jobs	🟨 Fewer FTEs and more job flexibility	🟨 Job losses	🟩 Preserves or creates jobs
Shareholder				
Earnings Reputation Growth	🟨 Capital investment in assets that are producing less. Use of gas enhances reputation.	🟩 Optimizes asset utilization and minimizes risk.	🟨 Loss of earnings.	🟨 Not running at full capacity but keeping the capital deployed.
Gov't/Community				
Environment Social/Economic Rate Impact on Growth	🟨 Not getting any savings; therefore gov't would see NSPI as not taking necessary action	🟩 Saving as much money as we can and not exposing customers to FAM.	🟨 Job losses yield poor public perception issue	🟨 Costs are being reduced but negative environmental performance and perception

🟥 Disallowance Risk/ Sanction/Labour Action

🟨 Taints Reputation and/or Increases Risk

🟩 Enhances/Maintains

Customer

Other Considerations

Recommendation Results

- Seasonal Operation at Lingan
    - 31 fewer FTE's (not all filled positions)
- Deferral of Planned Outages with less Capital Invested in Lingan
- Investigating Opportunities to Maximize PRB usage

Communication Plan Key Messages

INTERNAL AUDIENCES:

- Affected employees
- IBEW
- All other NSP employees

EXTERNAL AUDIENCES:

- UARB
- Public/Media
- Large customers
- Investors
- Politicians
- Intervenors

THESE ARE DIFFICULT DECISIONS WE TAKE VERY SERIOUSLY. WE ARE EXPLORING ALL ALTERNATIVES TO MINIMIZE THE TOTAL IMPACT ON OUR WORKERS WHILE IMPROVING OUR LONG-TERM ORGANIZATIONAL EFFICIENCIES.

THE PROPOSED CHANGES ARE PART OF OUR MANDATE TO ENSURE LOWER COSTS AND HIGHER VALUE FOR OUR CUSTOMERS IN THE CONTEXT OF MILL CLOSURES AND IMMINENT LOAD REDUCTION.

NSP IS PROUD OF OUR PARTNERSHIP WITH OUR INDUSTRIAL CUSTOMERS WHO INVEST IN OUR COMMUNITIES AND CREATE LOCAL JOBS. WE WANT TO SEE THEM SUCCEED AND CONTINUE PLAYING THAT ROLE ON THE GROUND.

APPENDICES

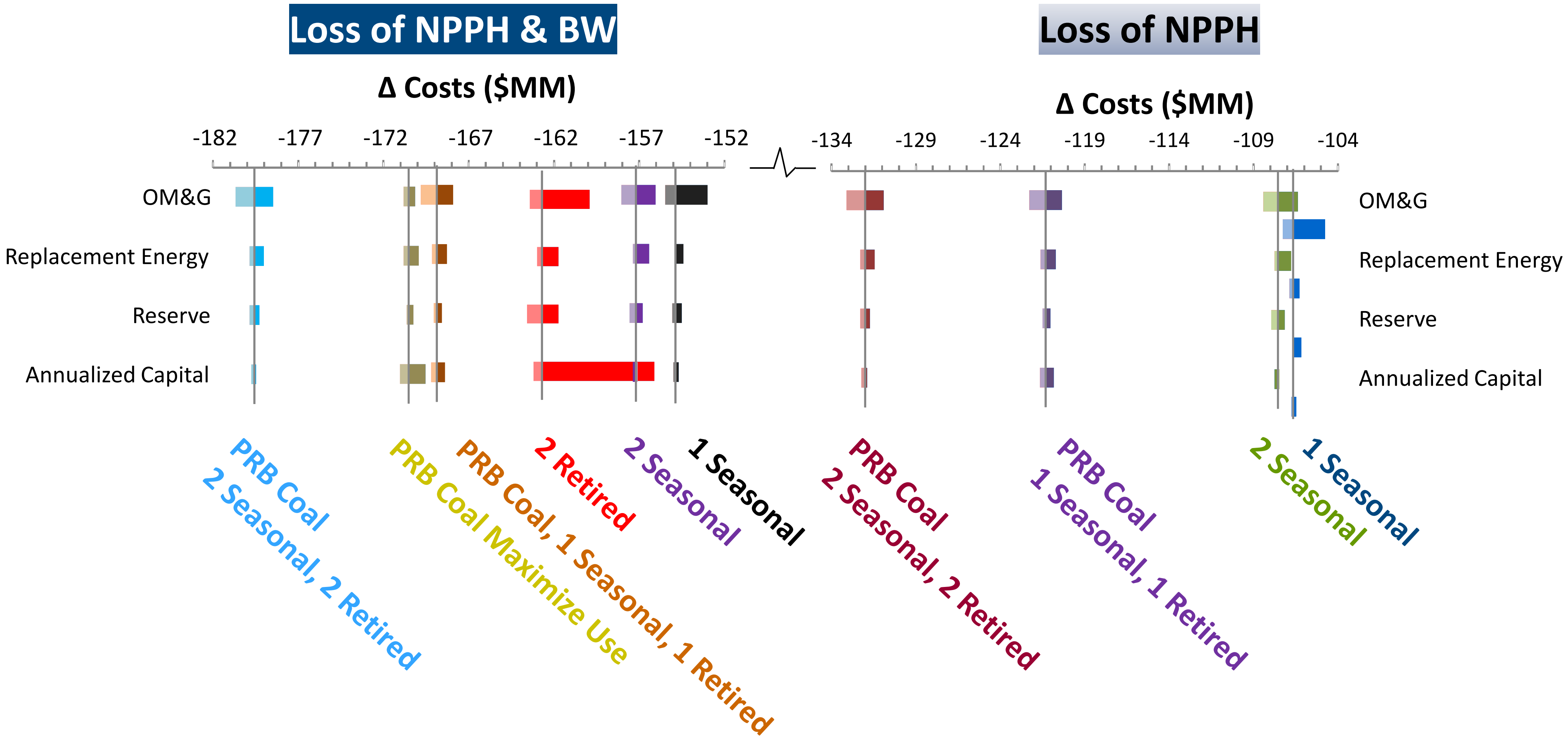
Strategist Dispatch Optimization Scenario Prioritization Matrix, Version 1

Strategy Themes	Loss of NP and BW	Loss of NP	Loss of NP PM1	Loss of BW	No loss of industrial load
Momentum	**4**	**2**	**3**	**5**	**1 (Base Case)**
GIS Fuel Flexibility	**8**	**7**		**9**	**6**
Minimize Dependence on Solid Fuel	**X**	**X**		**X**	**X**
Import Energy and Addt'nl Interruptibles	**10**				**11**
Solid Fuel Switching Derate					
Energy Exporter	**12**				

NOTE:

- Fuel Pricing is per the IRP Base Case Refresh
- Load is 2012 GRA refresh load forecast (the most recent load forecast)
- DSM is ENSC Base Case DSM as of Oct 2011

Sensitivity Analysis for **2013**: Only two overlapping ranges of uncertainty



Upside – Dark
Downside - Light

Rank order of graphs differs from Risk Profiles since results for only one year are displayed.

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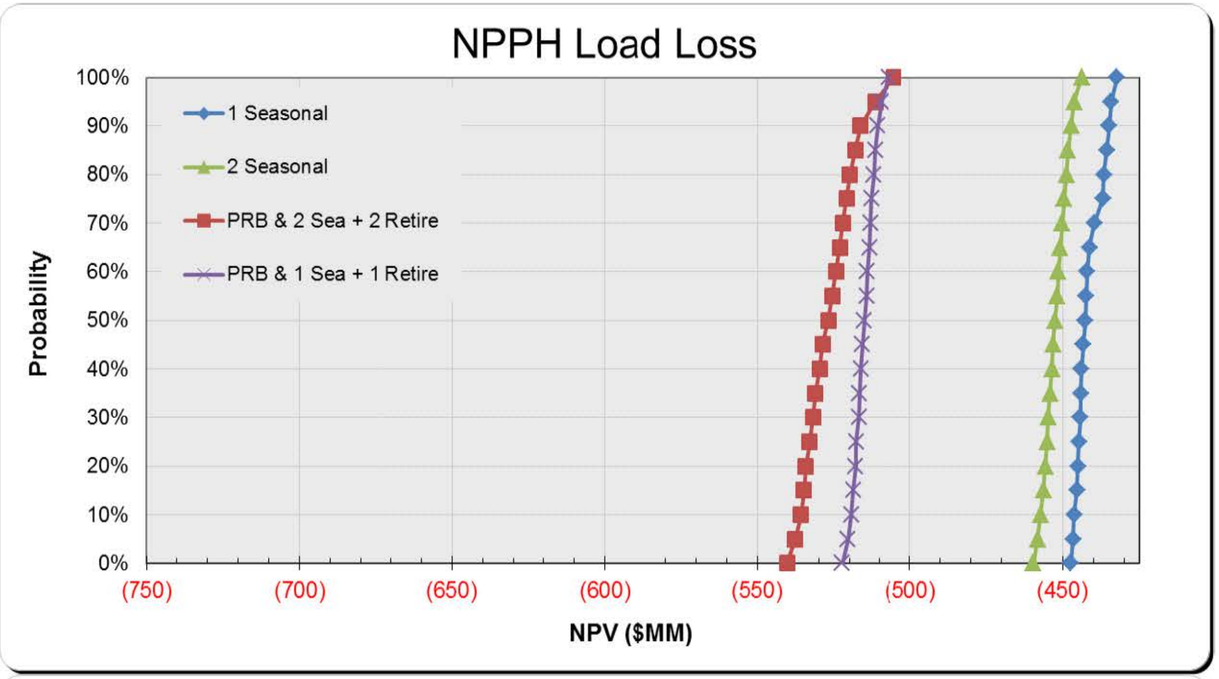
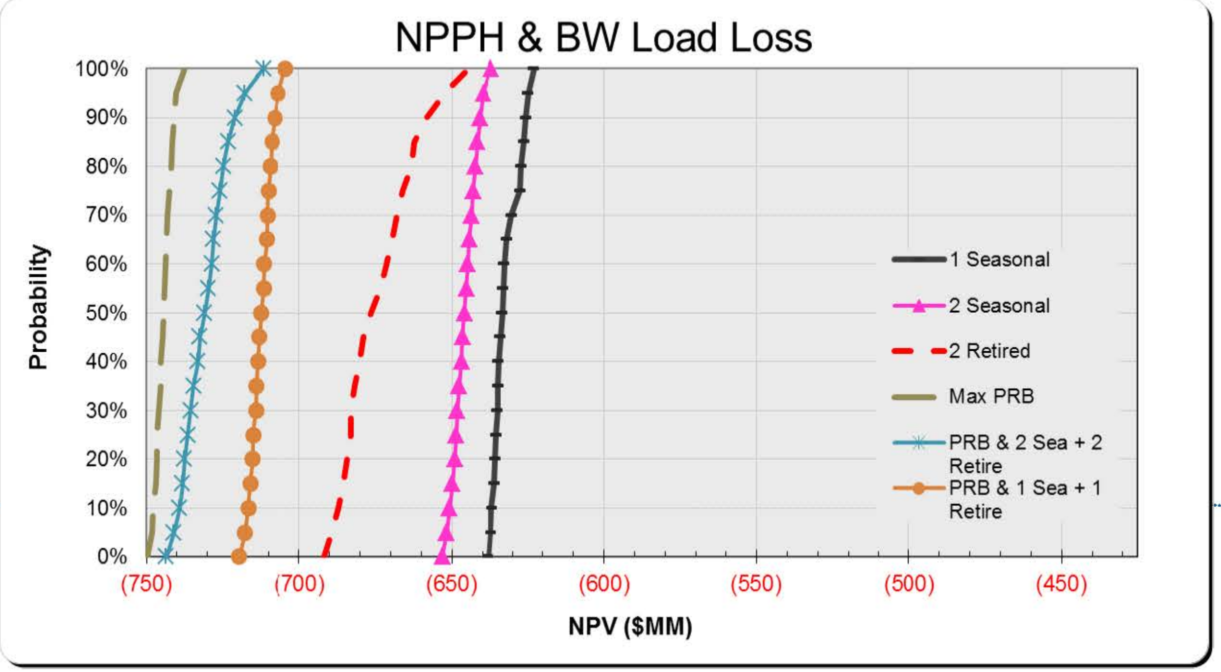
Actions including PRB are consistently lower cost options.

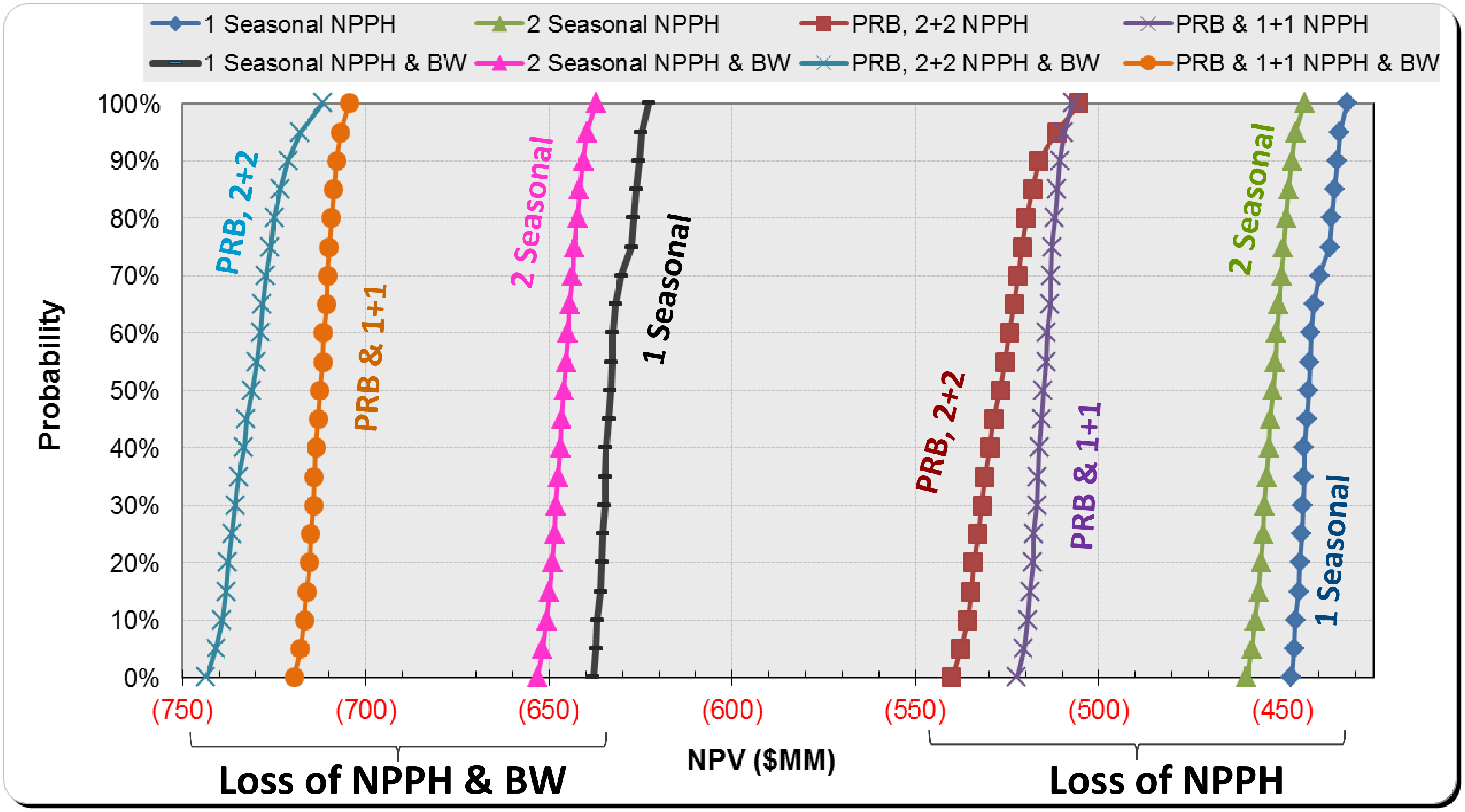
5-year DCF





Consistent pattern of common actions in both load loss scenarios.

5-year DCF



This graph includes only actions common to both load loss scenarios.

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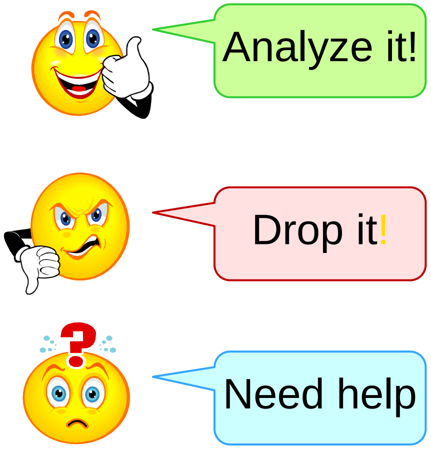
QUALITATIVE ASSESSMENTS



Analyze it!

Drop it!

Need help

*What is our qualitative judgment of “**Momentum**” strategy?*

DEFINITION

GIS Fuel Flexibility Strategy - Convert one unit at Trenton and Pt. Tupper to gas co-firing

OBJECTIVE

- Take advantage of lower gas pricing opportunities to help meet environmental constraints.
- Safeguard against volatility in fuel prices

WINS IF

- Price of NG is lower for some or all of the time over the next 2 to 3 years.

SHOWSTOPPERS

- Natural gas prices rise

ADVANTAGES

- Gas units could add to reserve by ramping up more quickly
- Portfolio approach to prime energy source
- Smaller environment foot print
- May enable units to comply with proposed fed. GHG regs
- Uses local fuel
- Minimizes impact on workforce

LIMITATIONS

- NG prices rebound to be more costly than coal
- NS offshore gas has a finite and midterm life expectancy
- NG prices rebound and more costly than coal
- High c.f. on gas leads to justification of new more efficient CC

RESPONSES

- lower emissions and increased flexibility (at TRE and PT)
- Increases in province NG use

UNIQUE POTENTIAL

HUNCHES

- Remains part of operating mode in mid-term

What is our qualitative judgment of “Seasonal Operation” strategy?

DEFINITION

Operate one (two) units seasonally and lay them up with a 10-day return. Different from practice at TUC1.

OBJECTIVE

Save OM&G expense by reducing planned outages and redeploying labour. Save variable production costs such as water and chemicals . Improve “average” heat rate by keeping remaining units at higher load.

WINS IF

- PP find all ways to optimize on the opportunities.

SHOWSTOPPERS

- Poor performance on remaining units cause very high replacement energy costs.

ADVANTAGES

- Less impact to employees compared to closing
- Overall revenue requirement decreases
- Real action to loss of sales
- “Hard Savings” vs. possible extra costs
- With 10-day recall, return of sales can be easily accommodated (no regrets)

LIMITATIONS

- PP do not find material savings
- labour savings but work force upset with reductions
- Other thermal units under performing and DAFOR+MOF higher than assumed levels

RESPONSES

- Employees will be impacted
- Customers may not see it as enough – coal units should close.

UNIQUE POTENTIAL

- Maybe export deals and exports may lay into facilitating supply of Reserve

HUNCHES

- IRP refresh may be required which may lead to coal unit retirement

What is our qualitative judgment of "**Shut Down**" strategy?

DEFINITION

Shut down one (two) units and advance installation of Fast-Acting Generation for reserve for Reserve if required

OBJECTIVE

Same as "Seasonal" strategy; save money.

WINS IF

SHOWSTOPPERS

ADVANTAGES

- May save more money than Seasonal operation
- Cause and result better aligned: Mills closes thus Power Plant closes
- Provides clarity for staff rather than gray area

LIMITATIONS

- Difficult to come back from if sales return or major event happens at another unit
- Big decisions which bring expectations of multi-stakeholder involvement

RESPONSES

- Different from 2009 IRP
- Significant loss of jobs in Sydney
- Employees will be moved, severed, lay-off
- Some stakeholders will view as predicted

UNIQUE POTENTIAL

- Share parts among remaining Lingan units
- Relieves ongoing demographic/skills problem with power engineers/PP technicians (or at least helps)

HUNCHES

- May come to this after detailed IRP

What is our qualitative judgment of "Solid Fuel Switching Derate" strategy? (page 1 of 2)

DEFINITION

Lower heating value fuels equal low MW and run selected units at lower CF, perhaps seasonally. Apply to 5 units.

OBJECTIVE

Significant MW de-rating for lower fuel costs

WINS IF

- Low CV's have price advantage relative to traditional fuels over the long haul

SHOWSTOPPERS

- Price of traditional fuels are equal to or less than low CV's

ADVANTAGES

- Keeps units available until 2015-2017 for option of NewPage restarting
- Low CV fuel contributes to meeting emission standards without capital investment in scrubbers
- Capital upgrades to use lower CV coal minimizes risk of using all coals (possible favorable impact on insurance premiums)
- PRB coals are low cost to mine
- Other units could use a higher sulfur, lower cost fuel
- PRB Donkin could be a good blend for Lingan 3 & 4
- Reduces county risk exposure (Columbia)
- Use of oil to supplement reserve
- Mw de-rating due to use of PRB on all 4 units at LIN equals 1+ complete unit shut down.
- Complementary with 45 year regulations
- Complementary with forward emission reductions initiatives such as Hg and S reductions
- No known impact on mercury sorbent performance.
- HR issues minimized as the same number of employees required to operate facilities
- Seasonal fuel blending/switching to reduce capacity and operating impacts
- Industry proven conversion technology

LIMITATIONS

- Payback on capital should match remaining unit life
- Insurers' concerns over fuel volatility
- Risk of slagging or other undesirable combustion effect
- No delivery available mid-Dec to mid-March
- May need to keep high heat rate coals available to manage through high load periods
- Capital upgrade for Coal system dust suppression and fire protection required.
- Improved coal galley housekeeping required.
- Extra shipping and handling costs may be incurred to store PRB over winter or non-delivery months
- Plan needs to be integrated with current inventory levels and coal supply agreements
- LIN Precipitator review required to understand Opacity and Mw's limits
- LIN Milling Plant limits need to be determined.

What is our qualitative judgment of "Solid Fuel Switching Derate" strategy? (page 2 of 2)

DEFINITION

Lower heating value fuels equal low MW and run selected units at lower CF, perhaps seasonally. Apply to 5 units.

OBJECTIVE

Significant MW de-rating for lower fuel costs

RESPONSES

- May lose volume discounts from traditional fuel suppliers

UNIQUE POTENTIAL

- Fits well with other approaches that result in low CF's
- Flexibility to respond to unfolding events

HUNCHES

- The strategy can help with reducing the impacts of significant Mw load reduction, but is not anticipated to be a sole solution.
- Capital modifications required
- PRB coal has shown good flash resistivity in previous testing which may lead to minimal opacity impacts at reduced loads
- The study would identify problem areas which may need to be up-graded for long term optimum unit operation (ie. Mill capacity)
- Can be done in combination with Seasonal operation s there is still headroom.

ACTIONS TO ASSESS THIS STRATEGY

- Develop a recommended implementation plan to optimize capacity, emissions and operating cost for 2012 and forward that includes a review Mw and emission reduction due to PRB use
- Determine the full emission reductions and the cost savings e.g. reduction in Sulphur (low cost fuel use at other facilities) and Mercury (savings from PAC)
- Evaluate the cost/benefit balance for various PRB fuel technical and operating options identified above

NON-CONFIDENTIAL

Request IR-7:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04, pdf Page 8/159, Lines 25-27. Is the "planned change in the Fuel Adjustment Mechanism" something other than the flow through of lower fuel costs? If so, please explain.

Response IR-7:

The 'planned change in the Fuel Adjustment Mechanism' references the 2013 Balance Adjustment (BA), which includes fuel costs incurred in 2010 that are currently being recovered through the 2010 FAM Deferral and scheduled to come out of rates January 1, 2013, and the 2011 FAM imbalance.

NON-CONFIDENTIAL

Request IR-8:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04, pdf Page 13/159, Lines 2-3

a) Please provide the studies supporting the statement that it is better to run plants at reduced capacity rather than shutting them down altogether.

b) Is NSPI aware of other utilities that have "mothballed" plants, leaving open the possibility of restarting them later? If so, please provide details.

Response IR-8:

(a) Please refer to Avon IR-6(b).

(b) NS Power is actively consulting with technical and management staff at Ontario Power Generation who have mothballed 6 of their large coal units over the course of the last two years.

Through the process of retiring the Glace Bay plant, NS Power gained experience in "mothballing" plants.

NS Power has carried out long-term lay up of oil and coal generating units in the past when their retirement/return to service was uncertain due to ranges of assumptions on demand growth and approval/commissioning dates of new generation sources. The possible loss of major customers is a similar situation.

NON-CONFIDENTIAL

Request IR-9:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04, pdf Page 13/159, Lines 7-9

Apart from seasonally running two of the four Lingan generating plants, please list and describe the steps taken by NSPI to minimize the cost of plants and equipment whose full capacity is no longer required

a) over the last six months

b) planned in 2013-2014

Response IR-9:

(a) NS Power reviewed its planned outage schedules and removed the major outage for Lingan Unit 2 from the 2012 plan which resulted in reduced capital requirements.

NS Power reduced 31 positions from its workforce in the generating facilities.

NS Power reviewed its Life Cycle Management (Asset Management) program to realign maintenance routines to equivalent running hours while maintaining acceptable levels of risk.

NS Power increased its consumption of lower cost, higher sulphur coals and petcoke.

NS Power's Power Production group engaged a consulting company to assist in developing and implementing a maintenance Continuous Improvement Program. At the end of 2012, all Thermal Plants and Hydro will have installed this Continuous Improvement Program.

(b) The results of a study into the loss of load (please refer to Avon IR-6(b)) are that seasonal operation of two coal units will produce the lowest overall cost to customers.

NS Power has and will continue to look for opportunities to reduce all costs – Operating and Maintenance, Fuel and Purchased Power and Capital.

Request IR-10:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 13 [Lines 25-26] states: "…which will make it the lowest cost, firm, renewable energy available to Nova Scotians"

a) What other source(s) of firm renewable energy is (or are) currently available in Nova Scotia?

b) What are their costs in comparison?

Response IR-10:

(a-b) NS Power's statement refers to the biomass facility currently under construction in Port Hawkesbury. As part of the regulatory approval process for that project a Request for Proposals (RFP) to provide firm, Renewable Electricity Standard (RES) qualified energy was conducted. The biomass plant was found to be more cost effective on a risk-adjusted basis than the other projects that bid in under the RFP. The Board Decision states:

> Mr. Whalen confirmed that there is a major fuel supply risk with one of the RFP proposals and a major risk of RES compliance with another. His conclusion is as follows:
>
> From my review of the RFP responses, I conclude that none of the options offered provides any significant economic advantage relative to the NPPH project; and none is less risky. [Exhibit N-62, p. 5]
>
> He went on to say that the responses to NS Power's RFP do not provide alternatives which are preferable to and eliminate the need for the Project.[1]

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[1] NSPI 2010 Capital Work Order CI # 39029 Port Hawkesbury Biomass Plant, UARB Decision, NSUARB-NSPI-P-128.10, October 14, 2010, paragraph 141 and 142.

NS Power currently purchases firm renewable energy from the Brooklyn cogen plant under a confidential contract. Subsequent to the market solicitation for firm renewable energy referenced above, Community Feed-In Tariff (COMFIT) rates were established for a variety of generation types including biomass fueled combined heat and power plants. The COMFIT rate for this type of plant is 17.5 cents per MWh which represents a significant premium to the expected cost of energy from the Port Hawkesbury plant. NS Power is not yet acquiring power from a project of this type under the COMFIT program.

NON-CONFIDENTIAL

Request IR-11:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 14 [Lines 7-8] states: "Our capital spending has grown in recent years as we have invested in renewable energy…"

a) Please indicate if NSPI anticipates that the trend toward higher capital expenditure will continue after 2014. If so, for how many years?

b) Please indicate the total capital expenditure in 2012, 2013 and 2014 that is attributable to renewables, including renewable-related transmission expenditures.

Response IR-11:

(a) Please refer to Attachment 1, 2012 Annual Capital Expenditure (ACE) Plan NSPI (HRM) IR-73 for NS Power's five year capital investment plan.

(b) The capital spend related to renewable generation for the years 2012-2014 included in the Application is as follows:

2012 ($M)	**2013 ($M)**	**2014 ($M)**
84.3	38.5	56.1

Request IR-73:

Reference: Annual Capital Expenditure (ACE) Plan for 2012 – 2016, page 8 of the 2012 ACE Plan.

Please provide details of the estimates for 2013, 2014, 2015 and 2016

Response IR-73:

	Capital Spend Forecast $M				
	2012	**2013**	**2014**	**2015**	**2016**
Sustaining Capital Investments					
Thermal Generation	$52.0	$42.4	$43.2	$44.0	$44.9
Hydro Generation	20.4	20.4	20.8	21.2	21.6
Transmission	40.8	20.0	20.4	20.8	21.2
Distribution	54.2	48.0	49.0	49.9	50.9
General Property	38.0	15.0	15.3	15.6	15.9
Strategic Capital Investments					
AMR Investment	5.5	5.0	5.0	5.0	5.0
CEF Load Control Project	1.3	2.0	0.2		
Power Production Asset & Work Management	3.4	0.2	-		
Additional Reliability Investment Distribution	12.6	10.0	10.0		
Additional Reliability Investment Transmission	9.4	10.0	9.0		
Wind Farm	-	-	30.0	190.0	
Other Wind	0.5	0.1	0.1	0.1	0.1
Marshall Falls Hydro Development	2.8	1.0	3.0	5.0	8.0
Hydro Infrastructural Renewal	10.0	20.0	20.0	20.0	18.0
Second Transmission Line to New Brunswick	-	2.0	20.0	40.0	70.0
Transmission Reinforcement	-	15.0	20.0	20.0	20.0
Harbour East 138kV Transmission	0.6	12.4			
Transmission Reliability	17.3	10.0	10.0	10.0	10.0
Fast Acting Generation #1	-	5.0	15.0	15.0	25.0
Fast Acting Generation #2				5.0	15.0
Port Hawkesbury 60 MW Biomass Project	56.0	8.4			
LED Lighting Replacement	5.7	22.0	22.0	24.0	26.0
Total Annual Capital Investment	**$330.3**	**$268.9**	**$313.0**	**$485.7**	**$351.7**

NON-CONFIDENTIAL

Request IR-12:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 16 [Lines 25-26] states: "Almost half of the total fuel increase for 2014, about $19 million, results from a forecast rise in natural gas prices and contract renewals."

a) Please provide the date of this natural gas price forecast.

b) Please provide the assumptions used in making this forecast.

c) Please provide a copy of the forecast and all analytical material used for predicting both open market and contract renewal gas prices.

Response IR-12:

(a) Per the FAM Plan of Administration, the natural gas price forecast is based on the simple average of the forward price strips immediately prior to December 30, 2011.

(b-c) Full details of these forecasts are available in the Confidential FAM Data Room binders GE0034 (2013 GRA Source Information), and GE0035 (2014 GRA Source Information) available for viewing at NS Power's offices.

Request IR-13

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 16 [Lines 26-27] states: "…Biomass fuel and forward coal prices are the other major fuel cost drivers in 2014."

a) Please provide a breakdown of the costs for biomass fuel for the commodity, processing and transportation.

b) Please indicate how NSPI is purchasing biomass fuel (long-term or short-term contracts, etc.).

c) Please provide copies of all requests for proposals for biomass fuels, as well as any processing or transportation services.

d) Please provide copies of all contracts related to the supply 2 of biomass, including the purchase of the commodity, processing services, and transportation.

e) What is the date of the coal forecast used for the 2014 fuel forecast?

f) Please provide the assumptions used in making this forecast.

g) Please provide a copy of the forecast and all analyses used in making the 2014 coal price prediction.

Response IR-13:

(a) The cost for biomass is based on the estimated as-fired price in $/MT assumed in the Port Hawkesbury biomass capital application.

NON-CONFIDENTIAL

(b-d) The procurement plan for biomass fuel is under development. The costs estimates for biomass in the 2014 forecast were based on the Port Hawkesbury biomass capital application.

(e) The coal costs in the 2014 fuel forecast were as of December 31, 2011.

(f-g) Please refer to FAM Data Room Confidential binder, GE0035 available for viewing at NS Power's offices.

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Request IR-14:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 17 [Lines 2-3] states: "…forward prices delivered to Tufts Cove are roughly $1.50 per MWh higher than those used in the 2013 rate forecast."

a) Please provide a copy of the forward price strip used here.

b) Does NSPI believe that forward prices are reliable predictors of future prices?

c) Has NSPI performed any analyses of how forward prices have historically compared to actual spot prices? If so, please provide copies of such analyses.

Response IR-14:

(a) Please refer to Confidential binders GE0034 and GE0035 for 2013 and 2014 prices respectively. These binders are available for viewing in the data room at NS Power's offices.

(b) The forward price is a reflection, at a specific point in time, of all the information the market has, and where it is willing to transact. As information changes, the forward price will change.

(c) No, this analysis has not been conducted.

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Request IR-15:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 17 [Lines 3-4] states: "Coal prices are also $9 million higher than accounted for in the 2013 forecast."

a) Please indicate that date on which this forecast was made.

b) Please provide copies of all analyses or purchased forecasts which were used to make this forecast.

c) Does NSPI believe that forward coal prices are reliable as a predictor of future prices?

d) Has NSPI performed any analyses of how forward coal prices have historically compared to actual spot prices? If so please provide copies of such analyses.

Response IR-15:

(a) The 2013 forecast is as of December 31, 2011.

(b) Full details of the forecast are available in the Confidential FAM Data Room binder GE0034, available for viewing at NS Power's offices.

(c) The forward price is a reflection, at a point in time, of all the information the market has, and where it is willing to transact. It is therefore reflective of the current market price of future positions. As additional information becomes available to the market, the forward price will change, and at times this can be produce a different price than a prior forward price for the same period.

(d) NS Power has not commissioned studies of how forward coal prices compare to spot pricing. The majority of fuel purchased by NS Power is not by spot purchases, but rather through mid-term and long-term contracts as required by the FAM Fuel Manual.

REDACTED

Request IR-16:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 17 [Lines 4-5] states: "This change [in coal prices] is due partly to higher future coal prices, and partly to the cost of low-sulphur coal required to meet emission constraints."

a) **Please provide separately which portion of the coal costs is attributable to higher expected commodity prices and how much is attributable to switch to low sulphur coal.**

b) **Please provide a copy of all analyses and calculations underlying this statement.**

Response IR-16:

(a) Higher commodity price makes up the majority of the change in coal costs between the 2013 and 2014 forecast. Of the $9 million change, approximately $1.4 million is attributable to additional low sulphur coal.

(b) The rise in coal commodity price is $0.17/MMBtu between the 2013 and 2014 forecasts. Based on the 2013 forecast consumption of [redacted] of coal, this represents approximately $9 million as quoted in the statement.

REDACTED

Request IR-17:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 17 [Lines 3-6] states: "Biomass fuel adds $8 million to 2014 fuel costs due to a forecast increase consistent with expectations in the original regulatory approval."

a) **Please provide a copy of all biomass price forecasts and calculations used in making the above statement.**

b) **Please provide a breakdown of the $8 million between commodity costs, processing and transportation.**

c) **Please discuss the original filing and regulatory approval and assumptions and sensitivities regarding the possible closure of either the New Page or Bowater paper mills?**

d) **Does NSPI believe that the closure of the mills will affect the demand for biomass and in turn the price of biomass? Please explain your answer.**

Response IR-17:

(a) This $8 million increase is made up of volume and price aspects. The volume component is due to the assumption that the plant will be running the full year in 2014, versus only running for nine months in 2013, representing about [redacted] of the increase. The price component is due to assumed inflation in 2014 of [redacted] over 2013 prices, representing about [redacted].

(b) Please refer to Avon IR-13.

REDACTED

(c) The Port Hawkesbury biomass capital application contained cost estimates for operating the biomass facility in the event of closure of the New Page mill. Please refer to Avon IR-10 for further discussion of NS Power's capital filing and regulatory approval.

(d) The closure of the New Page mill is anticipated to increase costs due to the reduction of by-products sourced from the NewPage plant - which are a lower cost source of biomass compared to harvested sources. However, the mill closure reduces demand for fiber in Nova Scotia. The net effect of these two factors is difficult to predict.

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Request IR-18:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 17 [Lines 14-16] states: "Investments in these systems will improve reliability and allow NS Power's electricity grid to handle new generation that will come on line, much of it intermittent in nature."

a) Please indicate what portion of the $23 million investment is attributable to the addition of wind to the system.

b) Please provide a list with related descriptions and costs for all projects included in your answer to (a).

Response IR-18:

(a-b) There is $28.1 million in wind capital forecasted in this filing for 2014 as construction work in progress. The reference noted makes the point that much of the new generation that will come on line in 2013 and 2014 will be intermittent in nature. NS Power will continue to invest in the strength of the transmission and distribution systems generally during the period. General improvements in reliability and in the systems will enhance the ability of the system to handle new intermittent generation sources.

The results of the pending Renewable Electricity Administrator (REA) award of renewable projects is anticipated to include wind projects and may influence the actual investment timing to support project schedules.

Request IR-19:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 19 [Line 22] states: "Energy costs are soaring around the globe."

a) **Could NSPI please explain this statement in the light of double digit declines in electric utility rates in nearby New England as described in the attached article?**

The Boston Globe
May 18, 2012
http://articles.boston.com/2012-05-18/business/31738344_1_natural-gas-national-grid11state-utility-regulators

Household electric bills down about 25 percent in Bay State

Lower costs for natural gas cited

By Erin Ailworth
GLOBE STAFF

The size of the average ratepayer's monthly electric bill in Massachusetts has shrunk to a six-year low, as utilities reduce rates because falling natural gas prices have made it cheaper to produce power, state energy officials said Thursday.

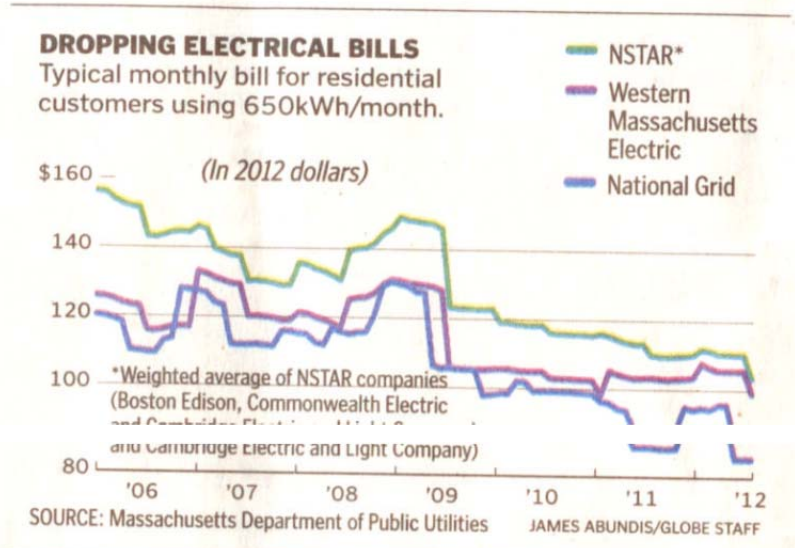
State data show that, on average, the average residential utility customer is now paying about $112 a month for electricity, down roughly 25 percent since 2006 when the cost was about $150 a month. The savings come as natural gas prices hover around their lowest point in about a decade. On Wednesday, natural gas closed just below $2.62 per million British thermal units, down almost 40 percent in the past 12 months.

Earlier this week, state utility regulators approved a nearly 16 percent decrease in electric rates for 1.1 million customers who get power from NStar, now a subsidiary of Northeast Utilities. The cut is expected to save customers about $6 a month. At the beginning of the month, National Grid lowered its electricity supply charge, cutting a typical customer's bill by an estimated $7.74.

While state energy officials lauded the drop in fuel prices, the state's energy and environmental affairs secretary, Rick Sullivan, urged utility customers to support public investments in renewable energy sources such as wind and solar power. Currently, the state spends $22 billion a year on energy, according to the state, much of which is imported from outside Massachusetts.

"It is imperative that we take advantage of this breather in energy cost increases to redouble our efforts to bring on line new clean energy resources that do not rely on dirty fossil fuels," he said in a statement.

Erin Ailworth can be reached at eailworth@globe.com. Follow her on Twitter @ailworth.



DROPPING ELECTRICAL BILLS
Typical monthly bill for residential customers using 650kWh/month.

*Weighted average of NSTAR companies (Boston Edison, Commonwealth Electric and Cambridge Electric and Light Company)

SOURCE: Massachusetts Department of Public Utilities
JAMES ABUNDIS/GLOBE STAFF

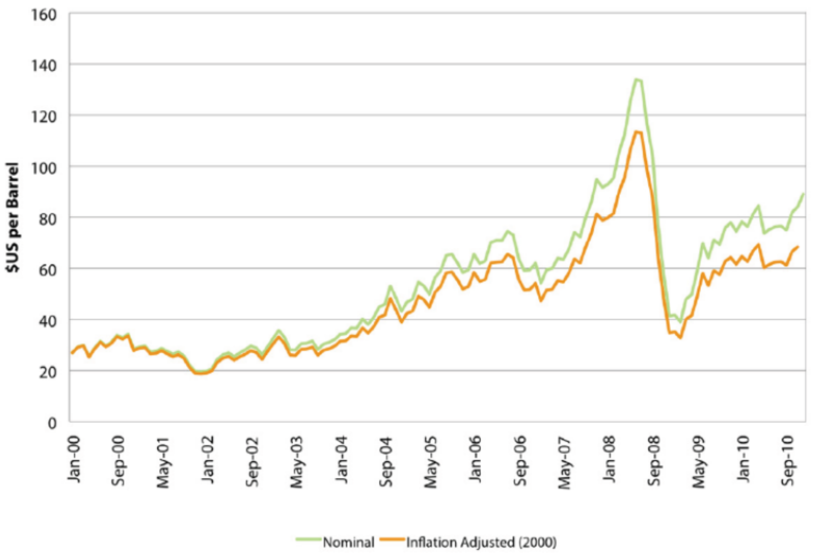
Response IR-19:

(a) NS Power looks at a variety of energy source costs and geographic regions when assessing long term trends in energy markets. Short-term upswings and price drops are a common theme in the volatile energy markets we have observed over the past several years. However, industry observers and experts agree that energy prices have generally risen over the past 10 years. We are looking to reduce the impact of this volatility and rising price environment on customers by reducing dependence on imported, high carbon fuel and using local renewables and increasing natural gas use. The charts below produced by the NEB in their "Energy Facts" report published in October 2011[1] offer a glimpse of the trend NS Power is referring to in its Application.

In DE-03 – DE-04, page 56 of 159 of the Application we have provided a chart showing the trend in the cost of imported solid fuel. Coal is the principal input fuel for NS Power. New England principally uses natural gas to fuel electricity generation and has benefitted from the low natural gas prices currently being realized across North America. NS Power has been able to moderate the impact of coal cost increases by using natural gas.

Figure 1: WTI Prices

Figure 1 shows crude oil prices over the 2000 to 2010 period for the West Texas Intermediate (WTI) benchmark.



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[1] http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/prcng/cndnnrgprcngtrndfct2011/cndnnrgprcngtrndfct-eng.pdf

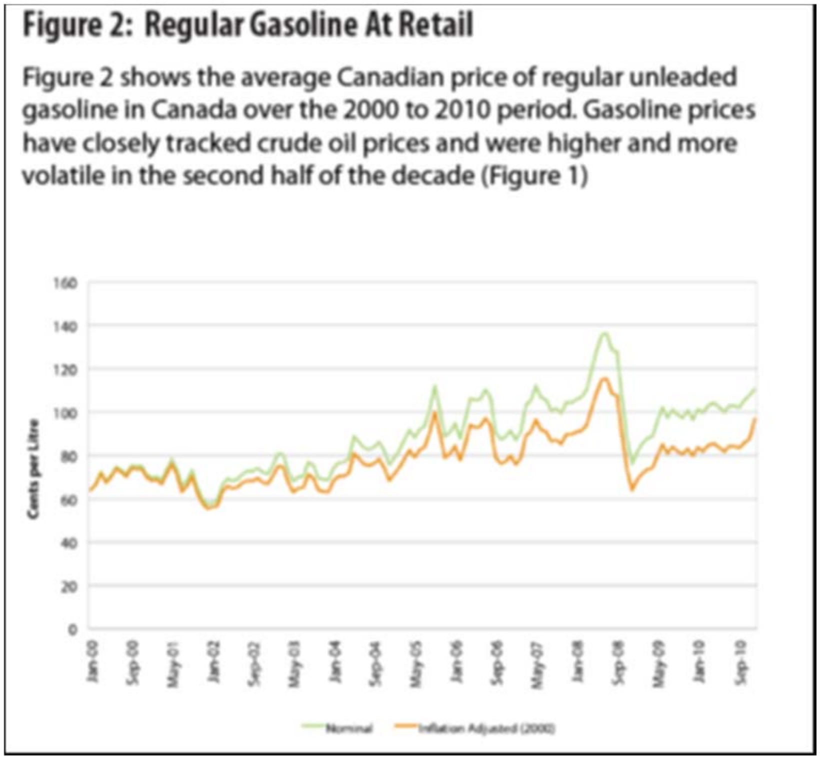

Figure 2: Regular Gasoline At Retail

Figure 2 shows the average Canadian price of regular unleaded gasoline in Canada over the 2000 to 2010 period. Gasoline prices have closely tracked crude oil prices and were higher and more volatile in the second half of the decade (Figure 1)

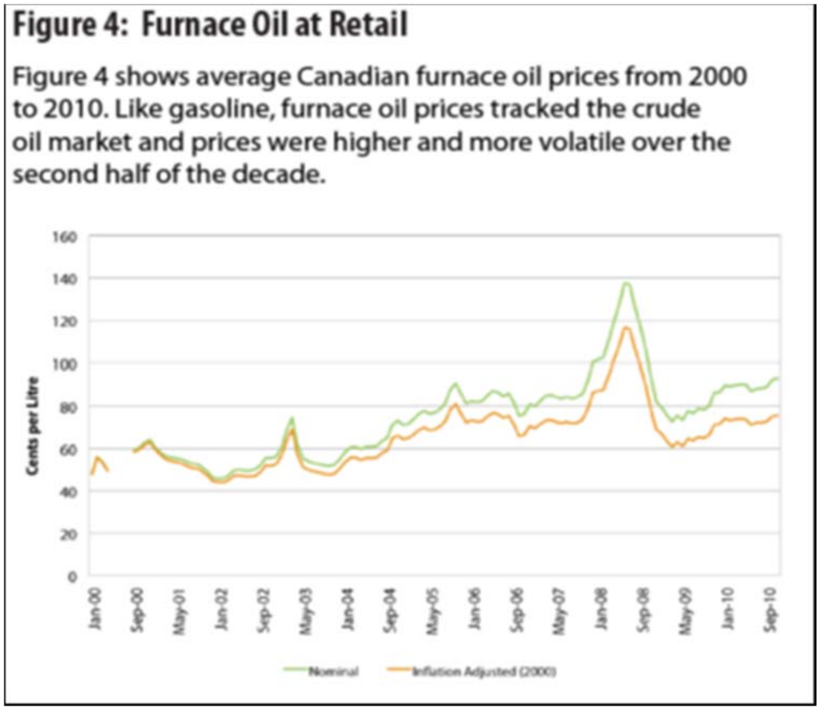

Figure 4: Furnace Oil at Retail

Figure 4 shows average Canadian furnace oil prices from 2000 to 2010. Like gasoline, furnace oil prices tracked the crude oil market and prices were higher and more volatile over the second half of the decade.

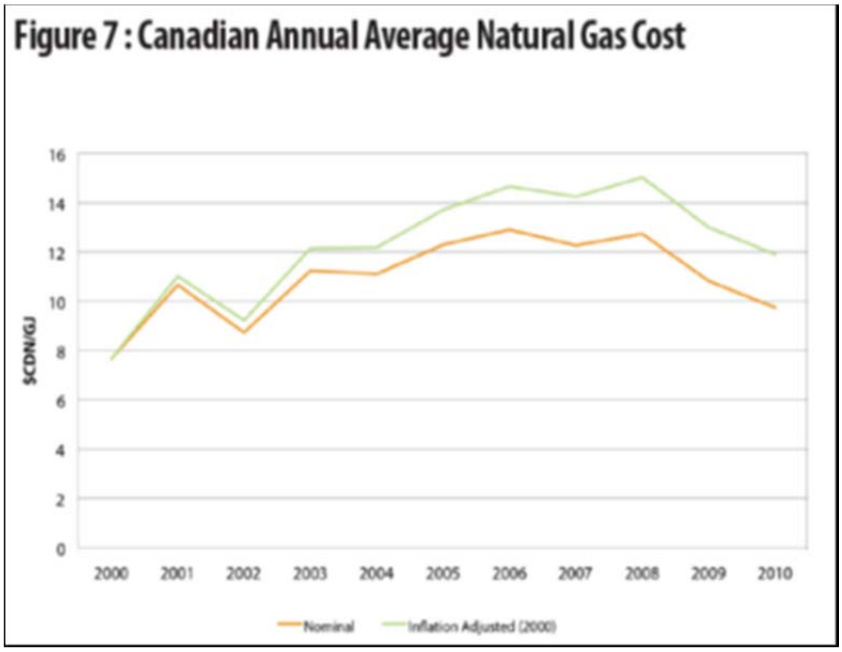

Figure 7 : Canadian Annual Average Natural Gas Cost

NON-CONFIDENTIAL

Request IR-20:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 20 [Lines 22-24] states: "For each customer class, an average 3 percent increase on January 1, 2013 and an average 3 percent increase on January 1, 2014, after factoring in the 2010 FAM deferral reductions in 2013 and 2014."

Please provide the percent increase for each rate class on January 1, 2013 and January 1, 2014, without factoring in the 2010 FAM deferral reductions.

Response IR-20:

Please refer to Appendix P, Attachment 2, pages 1 and 2, Column H of the Application.

NON-CONFIDENTIAL

Request IR-21:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 28 [Line 20] states: "By the time 2015 arrives, there will be other cost increases and adjustments to deal with."

Please provide a detailed list and explain the "other cost increases and adjustments" referred to here.

Response IR-21:

Please refer to Avon IR-3.

NON-CONFIDENTIAL

Request IR-22:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04, pdf Page 28/159, Lines 20-21

(a) Please provide estimates of the revenue requirements and rate increases required in 2015 and 2016 assuming (1) neither Bowater nor PWCC is operating; (2) Bowater is, but PWCC is not operating; and (3) both Bowater and PWCC are operating, with the latter only operating one paper machine. Show the fuel cost and non-fuel cost separately.

(b) What information does NSPI have that new load will appear by 2015?

Response IR-22:

(a-b) Please refer to SR-02, Load Forecast Report, Figure 15 of the Application for NS Power's current projection of Net System Requirement in 2015. The Company has not prepared revenue requirements or rate increase forecasts for 2015 or 2016 in this Application.

Request IR-23:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 30/159 [Line 22-25].

(a) As the FAM incentive was designed to incent NSPI to minimize fuel costs, (recognizing load is always variable), please explain why NSPI believes operation of the FAM should be suspended in 2013-2014 (apart from the fact it had been agreed to as part of a settlement package in the past).

(b) What monetary incentive does NSPI have to minimize fuel costs in 2013 - 2014?

Response IR-23:

(a) NS Power has indicated that the FAM should continue to operate with full reporting and cost tracking as currently takes place. The Rate Stabilization Plan proposed that any over or under recovery of fuel costs that would have applied to rates during the Rate Stabilization period be deferred until the end of the period for future recovery or refund. The Company proposed that the FAM incentive be suspended because one objective of the Rate Stabilization Plan is to deliver certainty to customers about rates for a two year period. The Rate Stabilization Plan re-sets the Base Cost of Fuel for each of the next two years, which places NS Power in the best position to avoid an imbalance between actual fuel costs and fuel revenue. As such, NS Power would expect to earn an incentive in each of the two years should the FAM incentive remain in place. It seems appropriate to NS Power that as part of the Rate Stabilization Plan, the Company should forego the opportunity to be paid an incentive while customers are adjusting to the loss of pulp and paper industry contributions to fixed costs. NS Power believes this is the most balanced approach for both the Company and its customers.

NON-CONFIDENTIAL

(b) The Company is incented by the desire to make its product affordable for its customers and by the regulatory oversight processes, which continue under the Rate Stabilization Plan, to minimize all costs for its customers, including fuel, by acting prudently in transacting on their behalf.

Request IR-24:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04, pdf Page 32/159, Lines 18-19

NS Power says that it supports restart of the Port Hawkesbury mill "so it can make a significant contribution to fixed cost recovery". However, the evidence at pdf Page 6/159, Line 22, says "there is no realistic prospect it [the Port Hawkesbury mill] will contribute more than a minimal amount to the fixed costs". Please reconcile these statements.

Response IR-24:

The statement at DE-03-DE-04, PDF page 32/159, Lines 18-19 of the Application refers to the post Rate Stabilization Plan period as indicated in the full excerpt:

> NS Power is committed to supporting the successful operation of the mill, so it can make a significant contribution to fixed cost recovery. Fixed cost contributions will benefit customers in the next two years by reducing the FCR amount. The Rate Stabilization Plan will provide two years of stability for all customers, while giving the mill a chance to **become** profitable and make the largest possible contribution to the fixed costs of the system. **(emphasis added)**

On the other hand, the statement at page 6, Line 22, as indicated in the full excerpt, refers specifically to the Rate Stabilization Plan period:

> The biggest factor in **this Application** is the loss of pulp and paper industry load. Over the last year, our two largest customers faced the prospect of permanent closure. The province's largest paper mill, in Port Hawkesbury, has been shut down since September 2011. We hope it will resume partial operation this fall under new ownership, but in the foreseeable future, there is no realistic prospect it will contribute more than a minimal amount to the fixed costs of our electricity system. **(emphasis added)**

NON-CONFIDENTIAL

Request IR-25:

Reference: Ex. N-2, Evidence 1 DE-03-DE-04 - pdf Page 36/159, Lines 4-5, 15-18

Please provide a detailed calculation of the referenced $53 million revenue shortfall in 2013.

Response IR-25:

Please refer to Multeese IR-6 Attachment 1.

NON-CONFIDENTIAL

Request IR-26:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 56 [Lines 8-10] states: "Over the last decade, prices for imported solid fuel have nearly doubled. Some of this increase is driven by the need to meet increasingly stringent emissions limits."

Please provide a breakout over the decade of the percentage of the solid fuel cost increases attributable to more stringent emission limits?

Response IR-26:

Emission limits have become more stringent over the past decade including sulphur dioxide (SO_2) and mercury (Hg). The most stringent year was 2010, before the amendments to Hg limits in July 2011. SO_2 emission limits have been reduced from 145,000 MT per year down to half this amount over the past decade. When comparing 2002 to 2011, approximately 90 percent of the solid fuel cost increase over the past decade is due to increased commodity pricing including low sulphur coal, and 10 percent of the increase results from the increased consumption of low sulphur coal. The increase in the amount of renewable energy is not taken into account in this calculation.

CONFIDENTIAL (Attachment Only)

Request IR-27:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 57 [Lines 13-14] states: "Conducting multiple test burns each year on new potentially lower cost solid fuel sources."

a) Please list all such test burns over the period 2008-2012 indicating the type of coal involved, the NSPI plant(s) at which the test burn was conducted and whether or not the coal was included in the portfolio of possible coals.

b) Please provide copies of all such test burn results.

Response IR-27:

(a) Please see Confidential Attachment 1 for a listing of the Test Burn Reports.

(b) Please refer to Confidential Attachment 2, available for viewing at NS Power's offices.

NON-CONFIDENTIAL

Request IR-28:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 62 [Lines 12-13] states: "…our ambitious shared goal of 40 percent renewable energy by 2020."

Please indicate what additional new renewable generation needs to be added to the NSPI system to achieve this goal.

Response IR-28:

Please refer to Attachment 1 which reflects updates to NS Power's Renewable Energy Standard (RES) Compliance Plan (Appendix C of the Application) since the time of filing.

RES 2013, 2015 and 2020 Compliance

	Assumes Bowater on , PH Mill off			Assumes Bowater on; PH Mill PM2 on (PM2 ~1000 GWh)		
	RES 2013	**RES 2015**	**RES 2020**	**RES 2013**	**RES 2015**	**RES 2020**
NSR	10,721	11,274	11,922	11,721	12,274	12,922
DSM effects	(DSM inlcuded)	528	1,263	(DSM inlcuded)	528	1,263
NSR less DSM	10,721	10,746	10,659	11,721	11,746	11,659
Sales (Assume 7% Losses)	10,020	10,043	9,961	10,954	10,977	10,896
RES %	10%	25%	40%	10%	25%	40%
RES Requirement (GWh)	1002	2511	3985	1095	2744	4358
NSPI Wind	254	254	254	254	254	254
Post 2001 IPPS	742	742	742	742	742	742
PH Biomass Project	323	418	418	269	388	388
COMFIT	0	100	300	0	100	300
Small Hydro - Marshall Falls	0	0	15	0	0	15
Minas Basin Biomass	0	55	55	0	55	55
Pre 2001 IPPS	156	156	156	156	156	156
NSPI Legacy Hydro	985	985	985	985	985	985
Maritime Link	0	0	1102	0	0	1102
Total Renewable Energy	1318	2709	4026	1264	2679	3996
Surplus/Deficit	316	198	41	169	-65	-363

Options for 2015 and Beyond Renewable Energy Supply

Wind - The Government appointed REA has issued an RFP for 300 GWh of RES qualifying energy	0 to 300	0 to 300
Maritime Link -Supplemental Purchase		0 to 400

Notes:
Jan 2012 GRA Load Forecast
NSPI Wind and IPP Wind as per 2014 GRA assumptions
PH Biomass project output is dependent on whether the PH Paper Mill is on or off.

NON-CONFIDENTIAL

Request IR-29:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 65 , Figure 4-5.

Please indicate the date of the solid fuel and natural gas price forecast(s) used to prepare Figure 4-5.

Response IR-29:

The solid fuel and natural gas price forecasts used for Figure 4-5 (and throughout the Application) are in accordance with the FAM Plan of Administration (POA) as of December 30, 2011.

NON-CONFIDENTIAL

Request IR-30:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 65 [Line 19] states: "Natural gas prices in 2014 are expected to increase more than solid fuel prices"

Please provide copies of all forecasts and analyses in NSPI's possession which support this statement.

Response IR-30:

Please refer to Confidential FAM Data Room binder GE0035, available for viewing at NS Power's offices.

REDACTED

Request IR-31:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 67 [Lines 28-30] , states: "We forecast purchased power to increase by 12 GWh in 2013, and then by an additional 105.1 GWh in 2014. The increase in 2014 is driven by the addition of renewables."

a) Please list the individual projects which will be added in 2013 and 2014.

b) Specify the generating technologies and contractually agreed unit costs for each project.

c) Please provide copies of all of the contracts for the incremental projects listed in your answer.

Response IR-31:

(a-b) The following projects are due to come online over 2013 and 2014:

Developer	**Location**	**Contract Signed**	**MWs**	**Cost**	**Expected COD**	**GWH/Year**	**PPA Status**
Wind Prospect Inc.	Fairmont	15-Dec-09	[redacted]	[redacted]	1-Jan-13	[redacted]	Approved
Scotian Windfields Inc.	Dunvegan	16-Dec-09	[redacted]	[redacted]	31-Jul-13	[redacted]	Under Revision
Scotian Windfields Inc.	Granville Ferry	16-Dec-09	[redacted]	[redacted]	31-Jul-13	[redacted]	Under Revision
Scotian Windfields Inc.	Isle Madame	16-Dec-09	[redacted]	[redacted]	31-Jul-13	[redacted]	Under Revision
Black River Wind Ltd.	Creignish Rear	15-Dec-09	[redacted]	[redacted]	1-Jul-13	[redacted]	Approved
Black River Wind Ltd.	Irish Mountain	15-Dec-09	[redacted]	[redacted]	1-Jul-13	[redacted]	Approved
Black River Wind Ltd.	South Cape Mabou	15-Dec-09	[redacted]	[redacted]	1-Jul-13	[redacted]	Approved
Infinite Energy Ltd.	Cape North	22-Dec-09	[redacted]	[redacted]	1-Jul-12	[redacted]	Approved
Confed. Power Inc.	Lingan	15-Dec-09	[redacted]	[redacted]	1-Jan-13	[redacted]	Under Revision

REDACTED

Developer	Location	Contract Signed	MWs	Cost	Expected COD	GWH/Year	PPA Status
MBPP	Hantsport	1-Sep-10	[redacted]	[redacted]	4th quarter, 2014	[redacted]	Under Revision

(c) Please refer to Confidential Attachments 1-10.

NON-CONFIDENTIAL

Request IR-32:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04, p. 69, Figure 4-7 and p. 70, Figure 4-8.

Please identify the items referred to as “other” in both figures.

Response IR-32:

In DE-03–DE-04 page 70 Figure 4-7 and Figure 4-8 of the Application, the “other” category includes fuel for resale, exports, marked to market, and water royalties.

Request IR-33:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 78 [Lines 17-19] states: "Stable generating capacity from the legacy fleet is required to back-up the variable nature of our current renewable portfolio. This situation contributes to our increased cost per MWh."

a) Please estimate the 2013 and 2014 cost of providing back-up power for the variable renewable generation.

b) Is this cost expected to increase or decrease as more wind generation is added to the NSPI system?

Response IR-33:

(a) The 2013 and 2014 costs directly attributable to backing up the variable nature of the renewable portfolio on the Nova Scotia power system consist of the following:

- higher heat rates for NS Power's thermal generating units
- increased annual start-up costs for thermal generating units as they are cycled more frequently
- increased expense associated with dispatching out of merit in some situations to accommodate the variable nature of wind generation
- increased maintenance resulting from more frequent cycling thermal generating units

Estimating the total cost for 2013 and 2014 that is directly attributable to backing up the variable nature of the renewable portfolio on the NS Power system requires further analysis. An estimate of these costs is not available at this time.

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(b) The costs directly attributable to backing up the variable nature of Nova Scotia's renewable portfolio are expected to increase as more wind generation is added to the power system in Nova Scotia. The renewables integration study will assist NS Power in better understanding the costs associated with integrating intermittent energy sources.

REDACTED

Request IR-34:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 79 [Line 1] states: "Making less use of our coal plants will increase their cost per unit of output."

a) Please indicate for each plant how large this cost increase is expected to be in 2013 and 2014 both in $/mWh and as a percent.

b) Have any internal or external studies been performed to identify the magnitude of these higher costs? If so, please provide a copy of each such study.

c) Please break your estimate of higher costs down into each component, e.g., deterioration in the heat rate, higher maintenance, etc.

Response IR-34:

(a) Partially Confidential Attachment 1 shows a breakdown of historical and forecast Operating, Maintenance and General (OM&G) expenses, for 2013 and 2014, by coal generating plant. As the cost increases associated with cycling our solid fuel based generating units are not well understood at this time, NS Power has not included increased costs that might be associated with this mode of operation in the 2013 and 2014 forecasts.

Between 2007 and 2014 solid fuel fired generation is expected to decrease by [redacted] and over this 8-year period plant OM&G is forecast to increase by [redacted]. The combined impact of these changes is an [redacted] increase in OM&G expense on a $/MWh basis.

REDACTED

(b) Please refer to Avon IR-6 Attachment 1 for a comparison of the different modes of operating the generating fleet resulting from lower load.

(c) Component costs for operating the units at lower loads have not been estimated. Changes in heat rates are due not only to lower loads but also variable generation, changes in fuel blends to meet emissions regulations. A breakdown of the individual contribution of these factors is not available.

OM&G Cost per MWh per Plant - 5 Years Actual

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast	% Change 2007 to 2014
Net Generation by Unit (MWh)									
Lingan - Unit 1	1,219,212	993,048	1,027,392	859,668	931,836	[redacted]	[redacted]	[redacted]	
Lingan - Unit 2	1,107,393	1,173,593	891,692	875,034	778,269	[redacted]	[redacted]	[redacted]	
Lingan - Unit 3	1,171,316	1,187,605	967,961	961,870	767,853	[redacted]	[redacted]	[redacted]	
Lingan - Unit 4	1,160,534	1,007,352	1,074,595	961,556	843,434	[redacted]	[redacted]	[redacted]	
Total Lingan	4,658,455	4,361,598	3,961,640	3,658,128	3,321,392	[redacted]	[redacted]	[redacted]	
Trenton - Unit 5	1,107,700	1,107,431	721,691	758,261	644,482	[redacted]	[redacted]	[redacted]	
Trenton - Unit 6	1,201,633	1,173,748	1,180,174	1,059,516	1,173,328	[redacted]	[redacted]	[redacted]	
Total Trenton	2,309,333	2,281,179	1,901,865	1,817,777	1,817,810	[redacted]	[redacted]	[redacted]	
Total Point Tupper	1,263,834	1,133,422	1,087,720	1,170,759	627,552	[redacted]	[redacted]	[redacted]	
Total Point Aconi	1,349,280	1,259,989	1,269,281	1,211,270	1,098,527	[redacted]	[redacted]	[redacted]	
Total Generation - Coal Plants	9,580,902	9,036,188	8,220,506	7,857,934	6,865,281	[redacted]	[redacted]	[redacted]	[redacted]
Operating Cost Per Location									
Lingan	$ 19,410,232	21,697,476	19,814,628	20,783,173	22,318,816	[redacted]	[redacted]	[redacted]	
Trenton	$ 12,900,298	12,828,058	14,802,005	14,829,545	13,589,562	[redacted]	[redacted]	[redacted]	
Point Tupper	$ 5,764,716	6,620,873	6,549,282	7,139,837	8,532,564	[redacted]	[redacted]	[redacted]	
Point Aconi	$ 7,508,494	8,392,322	8,264,758	8,808,742	8,896,394	[redacted]	[redacted]	[redacted]	
Total OMG - Coal Plants	$ 45,583,739	49,538,728	49,430,673	51,561,297	53,337,336	[redacted]	[redacted]	[redacted]	[redacted]

Total OMG/Mwh									
Lingan	$4.17	4.97	5.00	5.68	6.72	[redacted]	[redacted]	[redacted]	
Trenton	$5.59	5.62	7.78	8.16	7.48	[redacted]	[redacted]	[redacted]	
Point Tupper	$4.56	5.84	6.02	6.10	13.60	[redacted]	[redacted]	[redacted]	
Point Aconi	$5.56	6.66	6.51	7.27	8.10	[redacted]	[redacted]	[redacted]	
Total OMG - Coal Plants	$4.76	5.48	6.01	6.56	7.77	[redacted]	[redacted]	[redacted]	[redacted]

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Request IR-35:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 79 [Lines 4-5] states: "Over the long-term, however, the transformation we are undertaking will lead to costs that are lower and more stable compared to alternative strategies."

a) Please indicate in detail what "alternative strategies" were analyzed to reach this conclusion.

b) Did NSPI commission any consulting studies to examine such alternative strategies? If so, please provide copies of such.

c) What were the costs associated with such "alternative strategies"?

d) What were the major assumptions made in examining these strategies?

Response IR-35:

(a) The transformation of the generation portion of NS Power is driven by Provincial and Federal regulations and policies.

The lowest cost plan among the alternatives has been the subject of the Integrated Resource Plan (IRP) of 2007 and the IRP Update of 2009.[1]

(b) The IRP reports (2007 and 2009) have been previously shared with the Board and Intervenors.

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[1] NSPI Integrated Resource Plan (IRP) Report, NSUARB-NSPI-P-884, July 26, 2007 and NSPI 2009 Integrated Resource Plan Update Final Report, NSUARB-NSPI-P-884, November 30, 2009.

(c-d) Please refer to the IRP reports.

CONFIDENTIAL (Attachment Only)

Request IR-36:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 88 [Lines 21-22] indicates a full-year cost of operating the Port Hawkesbury biomass plant of $6.1 million.

a) Please break this figure down and separately identify major components such as labour, consumable supplies, and maintenance parts.

b) Please provide any supporting documents for how this figure was calculated.

Response IR-36:

(a) Please refer to Confidential Attachment 1.

(b) Please refer to Confidential Attachment 2 for Staffing Profile.

Primary Assumptions:

- Forecast reflects hire dates in staffing profile
- Overtime is at 12 percent
- Annual outage 3 weeks at $205,000/week
- Forced outages 4 per year at $20,500 each
- Fuel Handling contracted out

NON-CONFIDENTIAL

Request IR-37:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 89 [Lines 5-6] indicates a $4.1 million in savings from the transformation in operating mode for two Lingan units.

a) Please provide a breakdown of the components of this $4.1 million.

b) Please provide copies of any internal or external studies performed prior to making this decision.

Response IR-37:

(a) Please refer to Multeese IR-10.

(b) Please refer to Avon IR-6(b).

NON-CONFIDENTIAL

Request IR-38:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 89 [Lines 12-16] indicates: "The loss of pulp and paper industry load in 2011, combined with the addition of renewable energy, will reduce loads on our remaining fossil fuel plants. The change means that these units, which are designed to operate almost continuously, will operate at less than optimal capacity, and will turn on and off more frequently."

a) Please indicate by fossil plant unit any higher per mWh fuel costs which are expected to result from the above changed operational environment.

b) Indicate by fossil plant unit any higher maintenance costs which are expected to result from the above changed operational environment.

c) Were any internal or external studies performed of the expected effect of this changed operating mode? If so, please provide copies of such studies.

Response IR-38:

(a-b) Please refer to Avon IR-34(c).

(c) Please refer to Avon IR-34(b).

NON-CONFIDENTIAL

Request IR-39:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 p. 89 [Lines 16-18] states: "The operation of hydro units, meanwhile, will follow system load more closely to match a more variable generation protocol."

Please indicate whether this change is expected to have any negative or favourable cost impacts.

Response IR-39:

Hydro generation is planned and dispatched to maximize the value of this limited energy source. Historically, hydro would partially be reserved to offset high cost alternative sources at times of peak demand.

With more variable energy sources contributing to daily and yearly requirements, hydro's fast-acting response capabilities will mean that it will be increasingly required to follow variable generation. This use of hydro to follow generation may occur at non-peak periods and as a result, this limited resource will be less available during peak periods and its value will fall closer to the average marginal cost. This will increase fuel expense.

NON-CONFIDENTIAL

Request IR-40:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 Appendix B, p. 2, Figure 1-2.

Please confirm that copies of all contracts listed here, together with their supporting documentation have been placed in NSPI's confidential data room.

Response IR-40:

Confirmed.

REDACTED

Request IR-41:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 Appendix B, p. 3, Figure 1-3: [redacted]

a) **Please indicate the volumes that** [redacted] **does expect to supply** [redacted]

b) **Does NSPI intend** [redacted] **from other sources of supply? Please explain.**

Response IR-41:

(a) [redacted] expects to supply [redacted]. The total shortfall from the contract represents a total [redacted].

(b) NS Power is discussing the [redacted] sourced from the [redacted].

Request IR-42:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 Appendix B, p. 4 [Lines 25-26] states: "NS Power will be entering into new contracts in 2012 for freight for 2013 and beyond."

a) Does NSPI intend to conduct an international tender for freight services? And for both geared and bulker-type vessels? Please explain your answer.

b) As of the end of May 2012 has this process begun?

Response IR-42:

(a-b) Please refer to Liberty IR-12. Both geared and bulker-type vessels are included in the assessment for ocean freight.

NON-CONFIDENTIAL

Request IR-43:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 Appendix B, p. 5, Figure 1-1; p. 6, Figure 1-2; p. 7, Figures 1-3 and 1-4; p. 8, Figure 1-5; p. 9, Figure 1-6; p. 10, Figure 1-7

These figure numbers do not match the figure numbers referenced in the text. Please reconcile and indicate what the correct figure or text numbers should be.

Response IR-43:

Please refer to the list below:

- Appendix B, p. 5, Figure 1-1 should be titled Figure 1-5.
- Appendix B, p. 6, Figure 1-2 should be titled Figure 1-7.
- Appendix B, p. 7, Figure 1-3 should be titled Figure 1-6.
- Appendix B, p. 7, Figure 1-4 should be titled Figure 1-8.
- Appendix B, p. 8, Figure 1-5 should be titled Figure 1-9.
- Appendix B, p. 9, Figure 1-6 should be titled Figure 1-10.
- Appendix B, p. 10, Figure 1-7 should be titled Figure 1-11.

REDACTED

Request IR-44:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 Appendix B, p. 6 [Lines 16-17] states in regard to Figure 1-7: "This reflects a combination of a change in the fuel mix, lower petcoke pricing, and a softening in the global coal price."

a) Please indicate the petcoke price forecasts which underlie the substantial increase in petcoke volume shown in Figure 1-7 (labeled 1-2).

b) Please provide copies of all calculations, analyses and forecasts which served as a basis for Figure 1-7.

Response IR-44:

(a) The 2012 price forecast for petcoke was [redacted] versus [redacted] and [redacted] in the 2013 and 2014 forecasts respectively.

(b) Please refer to FAM Data Room Confidential binder GE0034 and GE0035 available for viewing at NS Power's offices.

Request IR-45:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 Appendix B, p. 8 [Lines 4-5] states, "The HFO and natural gas prices in this Application are produced using forward price curves and in-place hedges."

What has been NSPI's experience with the reliability of forward price curves for gas and HFO as predictors of actual spot prices?

Response IR-45:

The forward price is a reflection, at a specific point in time, of all the information the market has, and where it is willing to transact. As new information becomes available to the market, prices will change.

NS Power's experience is that: at some points in time, forward prices under-price the ultimate settlement prices; at some points in time, forward prices over-price the ultimate settlement prices; and, at times, forward prices come close to the ultimate settlement price.

REDACTED

Request IR-46:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 Appendix B, p. 8 [Lines 15-17] states: "The fuel cost increase in this Application relative to the original capital filing has increased on the basis that the lower cost residual biomass fuel from the mill is not available."

a) **Please provide detailed calculations to support the numbers in Figure 1-5.**

b) **Please provide copies of any contracts, negotiation minutes, or tender solicitations that support these altered costs.**

c) **Please compare these amounts with what NSPI/ NPPH had filed in the original capital filing when assessing the possibility of a NPPH shutdown and explain any variance.**

Response IR-46:

(a) The cost estimates for the capital filing in Figure 1-5 include the annual energy assumption of 388 GWh for cogeneration operation, and are based on an assumed total annual requirement of [redacted] consisting of mill residue plus harvested biomass. The fuel price from the capital filing of [redacted] for harvested biomass is multiplied by the estimated tonnes of biomass required for nine months of generation in 2013 of [redacted], giving fuel costs of [redacted]. The same calculation escalated by [redacted] and with the estimated tonnage requirement for the full year of [redacted], gives fuel costs for 2014 of [redacted].

(b) Please refer to response (a) and to Avon IR-13.

(c) Please refer to Liberty IR-26(a).

NON-CONFIDENTIAL

Request IR-47:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 Appendix B, p. 13 states: "For the current 12-month period, a maximum of 30 percent of the forecast USD requirement would remain open to allow for changes in the cash flow timing and volume of USD requirements".

Have these currency hedging guidelines remained the same over the past 5 years or have they evolved? If so, how?

Response IR-47:

The currency hedging guidelines have remained the same over the past five years.

REDACTED

Request IR-48:

Reference: Ex. N-3(i) DE-03-DE-04, Appendix B, pdf Page 17/556

(a) Provide the breakdown of natural gas cost between commodity cost and delivery cost. How are the delivery costs determined?

(b) Are gas costs forecast by month? If so, provide the monthly costs (commodity and delivery separately).

(c) What is meant by "lower cost residual biomass fuel is not available"? Why is it not available?

(d) Are the energy generation figures gross or net (of station requirements)?

(e) Please explain the change in generation between the Capital Filing and the GRA Filing.

(f) For the GRA filing, what are the assumptions regarding Port Hawkesbury operations?

Response IR-48:

(a-b) Please refer to OE-01A Confidential Attachment 1 Page 1 of 28 and OE-01A Confidential Attachment 4 Page 1 of 28 of the Application for the forecasts for natural gas by month. These forecasts are for natural gas delivered to the Tufts Cove plant, including commodity and delivery costs. The MN&P Canada transportation tolls are included in these forecast costs at [redacted] for 2013 and 2014. Please refer to FAM Data Room Confidential binder GE0034 and GE0035 available for viewing at NS Power's offices.

REDACTED

(c) In the Application, it is assumed that the Port Hawkesbury mill is not operating and, therefore, not producing residual biomass fuel. For this reason, residual biomass fuel is described as not being available in the Application.

(d) The energy generation figures are net of station requirements.

(e) The Application is based on stand-alone operation of the generation plant without the paper mill operating. The 2014 Capital filing is based on the mill operating and the generation plant operating in co-generation mode.[1]

In the stand-alone operating mode, all of the boiler steam energy is used to generate electricity. Only the energy between the superheated steam condition exiting the boiler and the start of condensation at the condenser inlet can be converted to electricity. All of the latent heat energy in the phase change between steam and condensed water is transferred to the cooling water.

In the co-generation operating mode, the steam is extracted from the steam turbine before it reaches the condenser. The mill's paper making process is capable of using both forms of steam heat energy to provide useful work in the mill's papermaking process. The mill recovers the steam energy from the superheated portion of the steam and also the latent heat from condensing the saturated steam back into water. This recovers some of the energy that would normally be transferred to the cooling water to be used to provide useful work.

The co-generation operating mode is capable of utilizing a greater portion of the boiler steam energy to provide useful work than when operating in the stand-alone mode; which

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[1] NSPI 2012 Annual Capital Expenditure Plan, NSUARB-NSPI-P-128.12, November 2, 2011.

REDACTED

provides a lower overall electric heat rate and a more efficient overall use of the boiler steam energy.

(f) Please refer to response (c).

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Request IR-49:

Reference: Ex. N-3(i), DE-03-DE-04, Appendix B (Partially Confidential) p. 8 of 13, pdf Page 19/556, Line 1

How would the operation of the Port Hawkesbury plant affect the need for LFO-fired generation?

Response IR-49:

NS Power understands this question to be referring to the Port Hawkesbury mill. The operation of the Port Hawkesbury mill is not expected to materially affect the need for Light Fuel Oil (LFO) fired generation.

REDACTED

Request IR-50:

Reference: Ex. N-3(i), Cook Evidence (Appendix D), pdf Page 37/556, 3rd and 4th Paragraphs (no line numbers provided)

(a) [redacted]

(b) [redacted]

Response IR-50:

(a-b) Please refer to FAM Confidential Dataroom binders NG0014, NG0015, NG0017 and NG0018 available for viewing at NS Power's offices.

NON-CONFIDENTIAL

Request IR-51:

Reference: Ex. N-3(i), DE-03-DE-04, Appendix E, pdf Page 28/556

Please explain the "consulting decrease due to completion of a one-time project".

Response IR-51:

Between 2010 and 2012, Power Production engaged a consulting company to assist in developing and implementing a maintenance Continuous Improvement Program. At the end of 2012, all Thermal Plants and Hydro will have installed this Continuous Improvement Program.

NON-CONFIDENTIAL

Request IR-52:

Reference: Ex. N-3(i), DE-03-DE-04, Appendix E, pdf Page 30/556

Please provide the derivation of the cost decreases due to seasonal operations at Lingan. What contracts are decreased due to seasonal operations at Lingan?

Response IR-52:

Please refer to Multeese IR-10. The result of the seasonal operation will be a delay in buying coal.

REDACTED

Request IR-53:

Reference: Ex. N-3(i), DE-03-DE-04, Appendix E, pdf Page 97/556

Please explain the write-offs of ($3,807,000) and [redacted]

Response IR-53:

The amounts indicated refer to variances between the 2013 Forecast amount for write-offs, and the 2011 actual experience and the 2013 Forecast and the 2012 Forecast, respectively. Write-offs are amounts that have been deemed unrecoverable. The 2013 Forecast amount for write-offs is $7,744,000, which is $3,807,000 less than the 2011 amount of $11,551,000. The 2011 actual write-offs included a one-time write-off provision that is not expected to reoccur. The 2013 Forecast amount for write-offs is [redacted] more than the 2012 Forecast, [redacted] of which is due to expected increases in average write-off amounts reflecting actual write-off experience and [redacted] of which is due to forecast increases associated with higher electricity rates, offset by expected recoveries. Please refer to DE-03 – DE-04, pages 93-94 of the Application.

REDACTED

Request IR-54:

Reference: Ex. N-3(i), DE-03-DE-04, Appendix E, pdf Page 100/556

What are the "Revenue Reclasses" of ($2,281,000) and [redacted]?

Response IR-54:

The amounts indicated refer to variances between the 2013 Forecast amount for revenue reclasses, and the 2011 actual amounts and the 2013 Forecast and the 2012 Forecast, respectively. The 2013 Forecast amount for revenue reclasses is $6,526,000, which is $2,281,000 less than the 2011 amount of $8,807,000, and is [redacted] less than the 2012 Forecast. In the past, under Canadian GAAP, NS Power netted certain revenues against operating costs. The amounts of revenues netted in the operating group's costs are included on the revenue reclass line of Corporate Adjustments. This adjustment in Corporate Adjustments increases operating costs by removing the revenues which were previously netted (under Canadian GAAP), and increases other revenues on the Income Statement (required under US GAAP). For details of the variances that make up the total revenue reclass referenced above on these specific operating costs items by business unit please refer to DE-03 – DE-04, Appendix E of the Application. This change due to US GAAP has no impact on rates.

NON-CONFIDENTIAL

Request IR-55:

Reference: Ex. N-3(i), DE-03-DE-04, Appendix F, pdf Page 101/556, Figure 1-2

a. Please explain the derivation of savings of $4.1 million for "Lingan Transformation".

b. Provide copies of all studies underlying the decision to do seasonal shutdowns of the Lingan units.

c. If the PWCC proposal does not go forward, how would this affect further changes in generation operations?

Response IR-55:

(a) Please refer to Multeese IR-10.

(b) Please refer to Avon IR-6(b).

(c) Please refer to Avon IR-6(b).

Request IR-56:

Reference: Ex. N-3(i), DE-03-DE-04, Appendix F, pdf Page 107/556, Lines 15-17

Please describe the activities of the Sustainability Group in more detail. Given that the Renewable Energy Administrator is responsible for acquiring new renewable resources, does this group have similar responsibility for obtaining new resources?

Response IR-56:

The primary responsibility of the Sustainability Group is to lead the transformation of the currently carbon intensive generation side of the business to a more balanced portfolio of prime energy sources. The group’s responsibilities include:

- Corporate Strategic Planning processes
- Renewable Electricity Standard (RES) Compliance and Carbon Management
- Prospecting and developing wind sites in preparation for construction in advance of 2015
- Partnerships with Independent Power Producers (IPPs) on renewable energy projects, including First Nations
- Supporting development initiatives including those where significant stakeholder work is required – and other special projects such as the Pacific West Commercial Corporation (PWCC) initiative
- Various initiatives such as Carbon Capture and Storage and Hydrogen enriched Natural Gas
- Policy analysis and government relations at the provincial and federal level related to the group’s mandate (for example respecting the proposed federal framework for retiring coal plants)
- Initiatives respecting new technologies such as electric vehicles and tidal generation and preparing for their introduction in Nova Scotia.

The Renewable Electricity Standard anticipates that new renewable energy will be provided by both IPPs and NS Power. The Sustainability Group is conducting pre-development work (for example; securing leases, measuring resources, environmental studies) for potential future NS Power projects. It is also working with local IPPs who intend to participate in the Renewable Electricity Administrator's (REA) Request for Proposals with NS Power as a minority investor in their projects.

The REA's role is to administer the Request for Proposal (RFP) process and to select which projects to proceed.

NON-CONFIDENTIAL

Request IR-57:

Reference: Ex. N-3(i), DE-03-DE-04, Appendix L (OATT Application), pdf Page 247/556, Lines 5-6

How is a municipal customer's "access to the Transmission System" different from that proposed to be provided to PWCC?

Response IR-57:

In the context of the Open Access Transmission Tariff (OATT), municipal customer's "access to the Transmission system" refers to the ability of the municipal customers to purchase electricity from a third-party and transmit this across the NS Power transmission system under the terms of the OATT.

Under the Load Retention Tariff mechanism proposed for Pacific West Commercial Corp. (PWCC), the customer will continue to use bundled electricity from NS Power (i.e. generation and transmission-related services) pursuant to the various agreements provided in that application.

NON-CONFIDENTIAL

Request IR-58:

Reference: Ex. N-3(i), DE-03-DE-04, Appendix L (OATT Application), pdf Page 249/556, Lines 22-23

How does the proposed service to PWCC differ from Network Integration Service?

Response IR-58:

Please refer to page 53 of the Open Access Transmission Tariff (OATT), where the following is provided:

> Preamble
>
> The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.[1]

Also, please refer to Avon IR-57.

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[1] NSPI, Application for an Open Access Transmission Tariff, NSUARB-NSPI-P-880, Approved May 31, 2005.

NON-CONFIDENTIAL

Request IR-59:

Reference: Ex. N-3(i)(C), DE-03-DE-04 – Appendix L p. 17 of 44, pdf Page 260/556, Lines 8-19

Please provide the supporting calculations to show the determination of regulation and frequency response capacity and operating reserves. Please provide the relevant information in electronic form.

Response IR-59:

Please refer to Multeese IR-55(c).

Operating Reserve requirements are established for the Maritimes Control Area by Northeast Power Coordinating Council (NPCC).[1] Operating Reserves are shared with the New Brunswick System Operator (NBSO) for the Maritimes Area. The Nova Scotia share of the Maritimes Area 10 Minute Operating Reserve is capped at the net output of the largest generator in Nova Scotia, currently Pt. Aconi at 171 MW.

NPCC requires that a portion (25 percent) of 10 Minute Reserve must be synchronized to the grid at all times (Spinning Reserve). Spinning Reserve for the Maritimes Area is determined to be 25 percent of the Area's ten minute responsibility (550 MW) or 137.5 MW. The Nova Scotia portion is a ratio of the 137.5 MW, determined by the net amount of NS Power's largest unit divided by the sum of NS Power's largest unit and the NBSO largest unit: (0.25 * 550) * (171 / (171 + 550)) = 33 MW.

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[1] https://www.npcc.org/Standards/Directories/NPCC%20Directory%2005%20Reserve.pdf

NON-CONFIDENTIAL

Request IR-60:

Reference: Ex. N-3(iii)(C), 3 OP 3, Attachment 1 – CONFIDENTIAL UMS Group – Nova Scotia Power OM&G Benchmarking Review Transmission Reliability Pdf page 274/1011

(a) Does NSPI establish a "target" level of reliability for the transmission system? If so, how is the target established? If not, how are investments prioritized if not with respect to the level of reliability to be achieved?

(b) Is NSPI satisfied with the present level of transmission reliability? Please explain.

Response IR-60:

(a) NS Power has reliability targets as outlined in Avon IR-64 Attachment 1, page 12. Investments are prioritized based on cost per avoided customer hour of interruption ($/ACHI). Please refer to Liberty IR-59.

(b) Improvements have been seen in areas where investments have been made. Further investments are required to reach targets.

NON-CONFIDENTIAL

Request IR-61:

Reference: Ex. N-3(iii) (C), 3 OP 3, Attachment 1 – CONFIDENTIAL UMS Group – Nova Scotia Power OM&G Benchmarking Review Distribution Reliability pdf Page 275/1011

(a) Does NSPI establish a "target" level of reliability for the distribution system? If so, how is the target established? If not, how are investments prioritized if not with respect to the level of reliability to be achieved?

(b) Is NSPI satisfied with the present level of distribution reliability? Please explain.

Response IR-61:

(a) NS Power has reliability targets outlined in Avon IR-64 Attachment 1 Page 12. Investments are prioritized based on cost per avoided customer hour of interruption ($/ACHI). Please refer to Liberty IR-59.

(b) Improvements have been seen in areas where investments have been made. Further investments are required to reach targets.

NON-CONFIDENTIAL

Request IR-62:

Reference: Ex. N-3(iii)(C), 3 OP 3 Attachment 1 – CONFIDENTIALUMS Group – Nova Scotia Power OM&G Benchmarking Review Distribution Reliability pdf Page 275/1011

(a) Please explain the methodology utilized by NSPI to record distribution outages. Does NSPI rely on an automated outage management system?

(b) Does NSPI have a GIS or other type of system which provides a model of the distribution system including connectivity of customers to distribution system assets? If not, does NSPI have plans to develop such a system?

Response IR-62:

(a) NS Power utilizes an outage management system (OMS) to monitor, analyze and record distribution outages. Outages are identified through a combination of customer calls and Supervisory Control and Data Acquisition (SCADA) indication from substations that have remote terminal units (RTUs) with connection to transmission, substation and distribution protection devices.

(b) Yes.

NON-CONFIDENTIAL

Request IR-63:

Reference: Ex. N-3(iii)(C), 3 OP 3 Attachment 1 – CONFIDENTIAL UMS Group – Nova Scotia Power OM&G Benchmarking Review pdf Page 385/1011

Please identify where the referenced "NSPI T&D Performance Summary" is located in the application. If it is not included in the application, please provide a copy.

Response IR-63:

Please refer to the matrix entitled "NSPI T&D Performance Summary" at page 121 of 245 of the Nova Scotia Power Operating, Maintenance, and General (OM&G) Benchmarking Review Final Report provided as OP-03 Attachment 1 of the Application.

NON-CONFIDENTIAL

Request IR-64:

Reference: Ex. N-3(iii)(C), 3 OP 3 Attachment 1 – CONFIDENTIAL UMS Group – Nova Scotia Power OM&G Benchmarking Review pdf Page 386/1011

Please identify where the referenced "5-year reliability investment plan" is discussed or located in the application. If it is not included in the application, please provide a copy.

Response IR-64:

Please refer to SBA IR-9 Attachment 1.

NON-CONFIDENTIAL

Request IR-65:

Reference: Ex. N-3(iii)(C), 3 OP 3 Attachment 1 – CONFIDENTIAL UMS Group – Nova Scotia Power OM&G Benchmarking Review

Please describe all programs and expenditures within the NSPI application that are proposed as a result of the UMS OM&G Benchmarking Review?

Response IR-65:

The NS Power Operating, Maintenance and General (OM&G) Benchmarking Review Final Report was finalized on May 5, 2012. The seven best practice recommendations are under review and no formal action plans have been developed or implemented to date. Several of the recommendations were already in place or underway, which include the following: Key Performance Indicators (KPIs) are standardized across Power Production and are used as a monitoring and measuring tool for performance tracking. These KPIs address safety, environment, production, financial and employee based initiatives. Through the Continuous Improvement Process the effectiveness of our maintenance programs is measured, tracked and reported on regularly basis. Standardized Shutdown Planning is an approach developed in-house and has been implemented across the fleet of thermal generating units. Along with these initiatives, NS Power is also currently focusing on asset management, work planning and generation transformation work. The business is fully engaged in these activities as they are the right priorities for now.

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Request IR-66:

Reference: Ex. N-3(iii)(C), 3 OP 3 Attachment 1 – CONFIDENTIAL UMS Group – Nova Scotia Power OM&G Benchmarking Review pdf Page 421/1011

(a) Has NSPI prepared the referenced "Gird (sic) Modernization Strategy and Plan"? If so, please provide a copy. If not, is NSPI preparing such a plan?

(b) Please discuss the UMS suggestion that an [redacted].

(c) Does NSPI agree that this is necessary? If so, why is it not reflected in the current application?

Response IR-66:

Please refer to Avon IR-65.

NON-CONFIDENTIAL

Request IR-67:

Reference: Ex. N-3 (iii)(C), OP-5, Attachments 1 and 2 pdf Pages 514-515/1011

How would maintenance schedules be affected with the PWCC load added? Please explain the note "LIN 1&2 place holders".

Response IR-67:

The thermal maintenance schedule will not be impacted by the addition of the Pacific West Commercial Corp. (PWCC) load. It is expected that the duration and extent of the seasonal operation at Lingan Generating Station will remain as forecasted. The PWCC energy forecast was built on the basis that all planned unit outages will remain the same. PWCC will assume all risks associated with the cost to serve their energy needs.

The note "LIN 1&2 place holders" is provided to highlight the fact that due to seasonal operation of these units, an Annual Planned Outage may not be required, due to the potential to complete maintenance activities during the economic outage periods.

REDACTED

Request IR-68:

Reference: Ex. N-3(iii), PARTIALLY CONFIDENTIAL 2013 GRA OP-06 Attachment 1, Page 1 of 2, pdf Page 517/1011Matter M04862 2012-05-30 NSPI (Avon) 1-38 CONFIDENTIAL pdf Page 53, Lines 24 and 25

(a) Please explain how the average heat rate of the Point Tupper Biomass plant can be [redacted] Btu/kWh in 2013 without NPPH while NSPI previously indicated that the average heat rate is [redacted] Btu/kWh in stand-alone mode and [redacted] Btu/kWh in co-generation operating mode.

(b) Please explain why the heat rate of the plant in stand-alone mode is worse than in co-generation mode.

(c) NSPI states it expects that in stand-alone mode the plant would produce [redacted] GWh and in co-generation mode would produce [redacted] GWh. Simple arithmetic would suggest the heat rate associated with the incremental output of [redacted] GWh ([redacted] GWh – [redacted] GWh) would be approximately [redacted] calculated thus:

$$\frac{(\text{[redacted] GWh x [redacted] Btu/kWh}) - (\text{[redacted] GWh x [redacted] Btu/kWh})}{(\text{[redacted] GWh} - \text{[redacted] GWh})} = \text{[redacted] Btu/kWh}$$

Please explain why this interpretation is not correct.

Response IR-68:

(a) The biomass plant design has become more refined since the capital application. These refinements continued with the 2013 GRA and further with the development of the recent Pacific West Commercial Corp. Load Retention Tariff (LRT) Application. The Pacific

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West application provides an updated heat rate in the range of [redacted] for stand-alone operation and represents the most recent information available.

(b) Please refer to response (a) and Avon IR-48(e).

(c) The formula shown is not correct for use with the co-generation cycle. The heat rates provided are only the electric heat rates relating to the steam energy utilized by the steam turbine to generation electricity and it is incorrect to use these numbers to calculate incremental heat rate between stand-alone generation with no turbine steam extraction and co-generation mode with turbine steam extraction.

In both stand-alone and co-generation operation, the boiler produces the same total amount of steam energy at the boiler steam outlet. In stand-alone mode, 100 percent of the boiler steam energy is used to generate electricity. In co-generation mode, approximately 75 percent of the boiler steam energy is used to generate electricity and 25 percent is extracted from the steam turbine after generating some electricity and used by the mill in the paper making process.

CONFIDENTIAL (Attachment Only)

Request IR-69:

Reference: **Ex. N-3(iii)(C), OP-08, Attachments 1, pdf Page 531/1011**

(a) **Are the "Firm Capacity MW" values derived from the "Firm Capacity%" or the other way around?**

(b) **Please explain how the starting numbers (1% or MW) was determined.**

(c) **Show the table with two more digits of precision (e.g., 10.12% instead of 10%).**

Response IR-69:

(a) The Firm Capacity MW values are derived from the Firm Capacity Percentage.

(b) The starting Firm Capacity MW values are determined by multiplying the Installed Capacity by the Firm Capacity Percentage. For sites that are not currently online the counterparty's energy bid is used. For sites that are online, a historical Firm Capacity Percentage is used.

(c) Please refer to Confidential Attachment 1.

NON-CONFIDENTIAL

Request IR-70:

Reference: Ex. N-3(iii)(C), 3 OP 9 Attachment 1, p.4 (pdf 536/1011) – CONFIDENTIAL Customer Outage Indices

(a) Please describe what is meant by "All-in data". Does this refer to outage levels including all major storms?

(b) Please describe the geography and utilities included in CEA Region 2.

(c) Is NSPI able to provide reliability statistics for Large Industrial customers only, perhaps based on interval meter data?

(d) Where NSPI collects interval metered data, does it flag the data as to whether zero recorded consumption is due to zero consumption versus a transmission or distribution outage?

(e) Does NSPI's SAIFI include momentary outages? Please discuss NSPI's ability to record momentary outages.

(f) What is the minimum outage duration that is typically reflected in NSPI's outage statistics?

Response IR-70:

(a) "All-in" data refers to all outages, including all categories of storm days.

(b) As per the Canadian Electricity Association (CEA) 2010 Service Continuity Report[1], CEA Region 2 includes the following utilities:

- ATCO Electric
- B.C. Hydro
- BELCO (Bermuda)
- BELIZE
- FortisAlberta
- FortisBC
- Hydro One
- Manitoba Hydro
- Maritime Electric Company
- New Brunswick Power
- Newfoundland & Labrador Hydro
- Newfoundland Power
- Nova Scotia Power Inc.
- Oakville Hydro Electricity Distribution
- SaskPower
- St. Lucia Electricity Services
- Veridian Connections

(c) NS Power does not separately track reliability statistics for Large Industrial customers only, but can assist individual customers as required.

(d) Yes.

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[1] Canadian Electricity Association, *2010 Annual Service Continuity Report on Distribution System Performance in Electrical Utilities*, Composite Non-Confidential Report, section 7, page 48.

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(e) No, NS Power's System Average Interruption Frequency Index (SAIFI) does not include momentary outages. NS Power is able to determine momentary outages by analysing Supervisory Control and Data Acquisition (SCADA) records from substations that have remote terminal units (RTUs) with connection to transmission and substation protection devices.

(f) One minute.

NON-CONFIDENTIAL

Request IR-71:

Reference: Ex. N-3(iv)(C), FOR-15, Attachment 1, pdf Page 29/29

Please show the derivation of the lag days for 2013 and 2014.

Response IR-71:

Please refer to Larkin IR-1.

NON-CONFIDENTIAL

Request IR-72:

Reference: Ex. N-3(v)(C), 5 RB-01 Attachment 1 – CONFIDENTIAL pdf Page 2/16, Line 6

Please explain the $9,114 negative addition in gross plant (retirement) for Wind Turbine in 2011.

Response IR-72:

The negative addition to gross plant for Wind Turbine in 2011 is related to an adjustment of the wind turbine asset retirement obligation asset that had been previously recorded in 2010. This adjustment was the result of the 2011 Depreciation Settlement.[1]

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[1] NSPI 2010 Depreciation Study, Minutes of Settlement, NSUARB-NSPI-P-891, April 5, 2011.

NON-CONFIDENTIAL

Request IR-73:

Reference: Ex. N-3(v)(C), RB-02-RB-16, Attachment 1, pdf Page 5 of 5, Line 20

Please explain the "allowance for working capital-settlement agreement adjustment" and how this was computed.

Response IR-73:

As part of the 2012 GRA Settlement Agreement, the allowance for working capital included in rate base was agreed to be $27.9 million.[1] The actual allowance for working capital was $54.8 million in the 2012 Application,[2] which was adjusted as part of the Settlement Agreement in order to adjust the cash working capital in rates using a "black box" approach. The allowance for working capital-settlement agreement adjustment in 2013 and 2014 was computed to adjust the actual allowance for working capital included in rate base in 2013 and 2014 to $27.9 million, the same level as included in 2012C. NS Power has not requested a change in rates associated with working capital.

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[1] NSPI 2012 General Rate Application, Settlement Agreement, NSUARB-NSPI-P-892, September 19, 2011.

[2] NSPI 2012 General Rate Application, NSUARB-NSPI-P-892, May 13, 2011,

NON-CONFIDENTIAL

Request IR-74:

Reference: Ex. N-3(viii)(C), OR-01, Attachment 1, pdf Pages 2-4/23

Please provide the spreadsheet, with formulas intact, of the current and proposed tariffs. In the alternative, provide a copy showing three additional digits of precision in the billing units.

Response IR-74:

Please refer to Attachment 1, filed electronically.

Current Tariffs	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			PRESENT
	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	RATES FORECAST
Above-the-line Classes	-																	2013
Residential Sector																		
Non-ETS	4,058.6	$ 0.12638	$ 512.9		$ -	$ -	-	$ -	$ -	4,058.6	$ 512.9	-	$ -	$ -	5.1	$ 10.83	$ 55.2	**$ 568.1**
ETS	13.7	$ 0.16435	$ 2.3	47.9	$ 0.12638	$ 6.1	153.0	$ 0.06468	$ 9.9	214.6	$ 18.2	-	$ -	$ -	0.1	$ 18.82	$ 2.4	**$ 20.6**
Total	**4,072.3**		**$ 515.2**	**47.9**		**$ 6.05**	**153.0**		**$ 9.9**	**4,273.2**	**$ 531.1**	**-**		**$ -**	**5.2**		**$ 57.60**	**$ 588.7**
Commercial Sector																		
Small General	39.7	$ 0.13370	$ 5.3	191.6	$ 0.11762	$ 22.5	-		$ -	231.3	$ 27.8	-	$ -	$ -	0.3	$ 12.65	$ 3.6	**$ 31.5**
General Demand	1,317.2	$ 0.09904	$ 130.5	1,118.1	$ 0.07006	$ 78.3	-		$ -	2,435.3	$ 208.8	7.2	$ 9.276	$ 67.2	-	$ -	$ -	**$ 276.0**
Large General																		
Without Trans. Own.	249.7	$ 0.07040	$ 17.6							249.7	$ 17.6	0.5	$ 11.702	$ 6.1				**$ 23.7**
With Trans. Own.	146.6	$ 0.07040	$ 10.3							146.6	$ 10.3	0.3	$ 11.382	$ 3.8				**$ 14.1**
Sub-total	396.3		$ 27.9							396.3	$ 27.9	0.9		$ 9.9				**$ 37.8**
Total	**1,753.2**		**$ 163.7**	**1,309.7**		**$ 100.9**				**3,062.9**	**$ 264.5**	**8.1**		**$ 77.1**	**0.3**		**$ 3.6**	**$ 345.2**
Industrial Sector																		
Small Industrial	175.3	$ 0.08965	$ 15.7	82.8	$ 0.06848	$ 5.7				258.2	$ 21.4	1.0	$ 6.854	$ 7.1	258.2			**$ 28.5**
Medium Industrial	498.8	$ 0.06390	$ 31.9							498.8	$ 31.9	1.5	$ 11.032	$ 16.1				**$ 48.0**
Large Industrial Firm																		
Without Trans. Own.	55.6	$ 0.06369	$ 3.5							55.6	$ 3.5	0.1	$ 10.469	$ 1.5				**$ 5.0**
With Trans. Own.	169.2	$ 0.06369	$ 10.8							169.2	$ 10.8	0.3	$ 10.149	$ 2.8				**$ 13.6**
Sub-total	224.8		$ 14.3							224.8	$ 14.3	0.4		$ 4.3				**$ 18.6**
Large Industrial Interr.																		
Without Trans. Own.	197.8	$ 0.06369	$ 12.6							197.8	$ 12.6	0.5	$ 7.039	3.6				**$ 16.2**
With Trans. Own.	498.8	$ 0.06369	$ 31.8							498.8	$ 31.8	1.1	$ 6.719	7.3				**$ 39.0**
Sub-total	696.6		$ 44.4							696.6	$ 44.4	1.6		10.9				**$ 55.2**
Total Large Industrial	**921.4**		**$ 58.7**						1	**921.4**	**$ 58.7**	**2.0**		**$ 15.1**				**$ 73.8**
ELI 2P-RTP	-		$ -							-	$ -	2.7	$ -	$ -		$ 20,700.00	$ -	**$ -**
Total Industrial	**1,595.5**		**$ 106.3**	**82.81**		**$ 5.7**				**1,678.4**	**$ 111.9**	**7.2**		**$ 38.3**	**258.2**		**0.0**	**$ 150.2**
Other																		
Municipal																		
Without Trans. Own.	118.6	$ 0.06609	$ 7.8							118.6	$ 7.8	0.3	$ 10.910	$ 3.6				**$ 11.4**
With Trans. Own.	74.1	$ 0.06609	$ 4.9							74.1	$ 4.9	0.2	$ 10.590	$ 2.0				**$ 6.9**
Sub-total	192.6		$ 12.7							192.6	$ 12.7	0.5		$ 5.6				**$ 18.3**
Unmetered[12]	104.4	$ 0.21398	$ 22.3							104.4	$ 22.3							**$ 22.3**
Total	**297.0**		**$ 35.1**							**297.0**	**$ 35.1**	**0.5**		**$ 5.6**				**$ 40.6**
Total Above-the-line	**7,718.1**		**$ 820.2**	**1,440.4**		**$ 112.6**	**153.0**		**$ 9.9**	**9,311.5**	**$ 942.7**	**15.8**		**$ 120.9**	**263.7**		**$ 61.2**	**$ 1,124.8**
Below-the-line Classes																		
GRLF	18.8	$ 0.05818	$ 1.1							18.8	$ 1.1							**$ 1.1**
Mersey Additional Energy	178.9	$ 0.05747	$ 10.3							178.9	$ 10.3							**$ 10.3**
Mersey Contract	189.0	$ 0.05257	$ 9.9							189.0	$ 9.9							**$ 9.9**
LRT	322.1	$ 0.06577	$ 21.2							322.1	$ 21.2							**$ 21.2**
GRLF, AE, Mersey Contract and LRT	708.8	$ 0.05995	$ 42.5							708.8	$ 42.5							**$ 42.5**
LED Capital Costs			$ 1.6								$ 1.6							**$ 1.6**
Total	**708.8**		**$ 44.1**							**708.8**	**$ 42.5**							**$ 44.1**
Total In-Province	**8,426.9**		**$ 864.2**	**1,440.4**		**$ 112.6**	**153.0**		**$ 9.9**	**10,020.3**	**$ 986.7**	**15.8**		**$ 120.9**	**263.7**		**$ 61.2**	**$ 1,168.9**
Exports	**28.9**	**$ 0.06243**	**$ 1.8**							**28.9**	**$ 1.8**							**$ 1.8**
Total Electric Revenue	**8,455.9**		**$ 866.0**	**1,440.4**		**$ 112.6**	**153.0**		**$ 9.9**	**10,049.2**	**$ 988.5**	**15.8**		**$ 120.9**	**263.7**		**$ 61.2**	**$ 1,170.7**
Misc. Revenues[2]			**$ 22.0**								**$ 22.0**							**$ 22.0**
Total Revenues			**$ 888.0**								**$ 1,010.5**							**$ 1,192.6**

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights

(2) Per kWh charge is not applicable as the class is made up of a number of rates

Appendix 6

Proof of Revenue

Proposed Tariffs	First KWh Block			Second KWh Block			Third KWh Block			Total KWHs		Demand			Base Charge			PROPOSED RATES FORECAST 2013
Above-the-line Classes	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	
	-																	
Residential Sector																		
Domestic Service	4,058.6	$ 0.14252	$ 578.4							4,058.6	$ 578.4				5.1	$ 10.83	$ 55.2	**$ 633.6**
Domestic Service Time of Day	13.7	$ 0.18595	$ 2.6	47.9	$ 0.14252	$ 6.8	153.0	0.07318	$ 11.2	214.6	$ 20.6				0.1	$ 18.82	$ 2.4	**$ 23.0**
Total	**4,072.3**		**$ 581.0**	**47.9**		**$ 6.83**	**153.0**		**$ 11.2**	**4,273.2**	**$ 599.0**				**5.2**		**$ 57.6**	**$ 656.6**
Commercial Sector																		
Small General	39.7	$ 0.15111	$ 6.0	191.6	$ 0.13294	$ 25.5				231.3	$ 31.5				0.3	$ 12.65	$ 3.6	**$ 35.1**
General	1,317.2	$ 0.11045	$ 145.5	1,118.1	$ 0.07814	$ 87.4				2,435.3	$ 232.9	7.2	$ 10.344	$ 74.9				**$ 307.8**
Large General																		
Without Trans. Own.	249.7	$ 0.07849	$ 19.6							249.7	$ 19.6	0.5	$ 13.046	$ 6.8				**$ 26.4**
With Trans. Own.	146.6	$ 0.07849	$ 11.5							146.6	$ 11.5	0.3	$ 12.726	$ 4.3				**$ 15.8**
Sub-total	396.3		$ 31.1							396.3	$ 31.1	0.9		$ 11.0				**$ 42.2**
Total	**1,753.2**		**$ 182.6**	**1,309.7**		**$ 112.8**				**3,062.9**	**$ 295.4**	**8.1**		**$ 86.0**	**0.3**		**$ 3.6**	**$ 385.0**
Industrial Sector																		
Small Industrial	175.3	$ 0.09998	$ 17.5	82.8	$ 0.07637	$ 6.3				258.2	$ 23.9	1.0	$ 7.644	$ 7.9				**$ 31.7**
Medium Industrial	498.8	$ 0.07127	$ 35.5							498.8	$ 35.5	1.5	$ 12.304	$ 17.9				**$ 53.5**
Large Industrial Firm																		
Without Trans. Own.	55.6	$ 0.07048	$ 3.9							55.6	$ 3.9	0.1	$ 11.587	$ 1.6				**$ 5.5**
With Trans. Own.	169.2	$ 0.07048	$ 11.9							169.2	$ 11.9	0.3	$ 11.267	$ 3.1				**$ 15.1**
Sub-total	224.8		$ 15.8							224.8	$ 15.8	0.4		$ 4.7				**$ 20.6**
Large Industrial Interruptible																		
Without Trans. Own.	197.8	$ 0.07048	$ 13.9							197.8	$ 13.9	0.5	$ 8.157	$ 4.1				**$ 18.1**
With Trans. Own.	498.8	$ 0.07048	$ 35.2							498.8	$ 35.2	1.1	$ 7.837	$ 8.5				**$ 43.6**
Sub-total	696.6		$ 49.1							696.6	$ 49.1	1.6		$ 12.6				**$ 61.7**
Total Large Industrial	**921.4**		**$ 64.9**							**921.4**	**$ 64.9**	**2.0**		**$ 17.4**				**$ 82.3**
Extra Large Industrial Interruptible	**-**		**$ -**							**-**	**$ -**		$ -	$ -				**$ -**
Total Industrial	**1,595.5**		**$ 118.0**	**82.8**		**$ 6.3**				**1,678.4**	**$ 124.3**	**4.5**		**$ 43.2**	**-**		**$ -**	**$ 167.5**
Other																		
Municipal																		
Without Trans. Own.	118.6	$ 0.07368	$ 8.7							118.6	$ 8.7	0.3	$ 12.163	$ 4.0				**$ 12.7**
With Trans. Own.	74.1	$ 0.07368	$ 5.5							74.1	$ 5.5	0.2	$ 11.843	$ 2.2				**$ 7.7**
Sub-total	192.6		$ 14.2							192.6	$ 14.2	0.5		$ 6.2				**$ 20.4**
Unmetered[12]	104.4	$ 0.23597	$ 24.6							104.4	$ 24.6							**$ 24.6**
Total	**297.0**		**$ 38.8**							**297.0**	**$ 38.8**	**0.5**		**$ 6.2**				**$ 45.0**
Total Above-the-line	**7,718.1**		**$ 920.4**	**1,440.4**		**$ 126.0**	**153.0**		**$ 11.2**	**9,311.5**	**$ 1,057.6**	**13.1**		**$ 135.4**	**5.5**		**$ 61.2**	**$ 1,254.2**
Below-the-line Classes																		
GRLF	18.8	$ 0.05818	$ 1.1							18.8	$ 1.1							**$ 1.1**
Mersey Additional Energy	178.9	$ 0.05747	$ 10.3							178.9	$ 10.3							**$ 10.3**
Mersey Contract	189.0	$ 0.05257	$ 9.9							189.0	$ 9.9							**$ 9.9**
LRT	322.1	$ 0.06577	$ 21.2							322.1	$ 21.2							**$ 21.2**
GRLF, AE, and Mersey Contract	708.8	$ 0.05995	$ 42.5							708.8	$ 42.5							**$ 42.5**
LED Capital Costs			$ 2.0							-	$ 2.0							**$ 2.0**
Total	**708.8**		**$ 44.5**							**708.8**	**44.5**							**$ 44.5**
Total In-Province	**8,426.9**		**$ 964.9**	**1,440.4**		**$ 126.0**	**153.0**		**$ 11.2**	**10,020.3**	**$ 1,102.1**	**13.1**		**$ 135.4**	**5.5**		**$ 61.2**	**$ 1,298.7**
Exports	**28.9**	**$ 0.06243**	**$ 1.8**							**28.9**	**$ 1.8**							**$ 1.8**
Total Electric Revenue	**8,455.9**		**$ 966.7**	**1,440.4**		**$ 126.0**	**153.0**		**$ 11.2**	**10,049.2**	**$ 1,103.9**	**13.1**		**$ 135.4**	**5.5**		**$ 61.2**	**$ 1,300.5**
Misc. Revenues[2]			**$ 22.6**								**$ 22.6**							**$ 22.6**
Total Revenues			**$ 989.3**								**$ 1,126.5**							**$ 1,323.0**

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights

(2) Per kWh charge is not applicable as the class is made up of a number of rates

Note: Any differences between calculated and reported revenues are due to rounding of tariffs.

Appendix 6

Proof of Revenue

VARIANCE	First KWh Block			Second KWh Block			Third KWh Block			Total KWHs		Demand			Base Charge			Revenue Forecasts
	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	
Above-the-line Classes	-																	
Residential Sector																		
Non-ETS		$ 0.01614	$ 65.5	-	$ -	$ -	-	$ -	$ -	-	$ 65.5	-	$ -	$ -	-	$ -	$ -	**$ 65.5**
ETS	-	$ 0.02160	$ 0.3	-	$ 0.01614	$ 0.8	-	0.008500118	$ 1.3	-	$ 2.4	-	$ -	$ -	-	$ -	$ -	**$ 2.4**
Total	**-**	**$ -**	**$ 65.8**	**-**	**$ -**	**$ 0.77**	**-**	**0**	**$ 1.3**	**-**	**$ 67.9**	**-**	**$ -**	**$ -**	**-**	**0**	**$ -**	**$ 67.9**
Commercial Sector																		
Small General	-	$ 0.01741	$ 0.7	-	$ 0.01532	$ 2.9	-	0	$ -	-	$ 3.6	-	$ -	$ -	-	$ -	$ -	**$ 3.6**
General Demand	-	$ 0.01141	$ 15.0	$ -	$ 0.00808	$ 9.0	-	0	$ -	-	$ 24.1	-	$ 1.07	$ 7.7	-	$ -	$ -	**$ 31.8**
Large General	-	$ -	$ -	0	$ -	0	0	0	0	-	$ -	-	$ -	$ -	0	0	0	**$ -**
Without Trans. Own.	-	$ 0.00809	$ 2.0	$ -	$ -	$ -	-	0	$ -	-	$ 2.0	-	$ 1.34	$ 0.7	-	$ -	$ -	**$ 2.7**
With Trans. Own.	-	$ 0.00809	$ 1.2	0	$ -	0	0	0	0	-	$ 1.2	-	$ 1.34	$ 0.5	0	0	0	**$ 1.6**
Sub-total	-	$ -	$ 3.2	0	$ -	0	0	0	0	-	$ 3.2	-	$ -	$ 1.1	0	0	0	**$ 4.4**
Total	**-**	**$ -**	**$ 18.9**	**-**	**$ -**	**$ 12.0**	**0**	**0**	**0**	**-**	**$ 30.9**	**-**	**$ -**	**$ 8.9**	**-**	**0**	**$ -**	**$ 39.8**
Industrial Sector																		
Small Industrial	-	$ 0.01033	$ 1.8	-	$ 0.00789	$ 0.7	-	0	$ -	-	$ 2.5	-	$ 0.79	$ 0.8	(258.2)	$ -	$ -	**$ 3.3**
Medium Industrial	-	$ 0.00737	$ 3.7	-	$ -	$ -	-	0	$ -	-	$ 3.7	-	$ 1.27	$ 1.9	-	$ -	$ -	**$ 5.5**
Large Industrial Firm																		
Without Trans. Own.	-	$ 0.00679	$ 0.4	-	$ -	$ -	-	0	$ -	-	$ 0.4	-	$ 1.12	$ 0.2	-	$ -	$ -	**$ 0.5**
With Trans. Own.	-	$ 0.00679	$ 1.1	0	$ -	0	0	0	0	-	$ 1.1	-	$ 1.12	$ 0.3	0	0	0	**$ 1.5**
Sub-total	-	$ -	$ 1.5	-	$ -	$ -	-	0	$ -	-	$ 1.5	-	$ -	$ 0.5	-	$ -	$ -	**$ 2.0**
Large Industrial Interr.																		
Without Trans. Own.	-	$ 0.00679	$ 1.3	-	$ -	$ -	0	0	0	-	$ 1.3	-	$ 1.12	$ 0.6	-	0	$ -	**$ 1.9**
With Trans. Own.	-	$ 0.00679	$ 3.4	-	$ -	$ -	0	0	0	-	$ 3.4	-	$ 1.12	$ 1.2	-	0	$ -	**$ 4.6**
Sub-total	-	$ -	$ 4.7	-	$ -	$ -	0	0	0	-	$ 4.7	-	$ -	$ 1.8	-	0	$ -	**$ 6.5**
Total Large Industrial	**-**	**$ -**	**$ 6.3**	**0**	**$ -**	**0**	**0**	**0**	**-1**	**-**	**$ 6.3**	**-**	**$ -**	**$ 2.2**	**0**	**0**	**0**	**$ 8.5**
Extra Large Industrial Interruptible	**-**	**$ -**	**$ -**	**0**	**$ -**	**0**	**0**	**0**	**0**	**-**	**$ -**	**(2.73)**	**$ -**	**$ -**	**0**	**-20700**	**0**	**$ -**
Total Industrial	**-**	**$ -**	**$ 11.7**	**-**	**$ -**	**$ 0.7**	**0**	**0**	**0**	**-**	**$ 12.4**	**(2.73)**	**$ -**	**$ 4.9**	**-258.2**	**0**	**0**	**$ 17.3**
Other																0		
Municipal																		
Without Trans. Own.	-	$ 0.00759	$ 0.9	0	$ -	0	0	0	0	-	$ 0.9	-	$ 1.25	$ 0.4	0	0	0	**$ 1.3**
With Trans. Own.	-	$ 0.00759	$ 0.6	0	$ -	0	0	0	0	-	$ 0.6	-	$ 1.25	$ 0.2	0	0	0	**$ 0.8**
Sub-total	-	$ -	$ 1.5	0	$ -	0	0	0	0	-	$ 1.5	-	$ -	$ 0.6	0	0	0	**$ 2.1**
Unmetered[12]	-	$ 0.02199	$ 2.3	0	$ -	0	0	0	0	-	$ 2.3	-	$ -	$ -	0	0	0	**$ 2.3**
Total	-	$ -	$ 3.8	0	$ -	0	0	0	0	-	$ 3.8	-	$ -	$ 0.6	0	0	0	**$ 4.4**
Total Above-the-line	**-**	**$ -**	**$ 100.3**	**-**	**$ -**	**$ 13.4**	**-**	**0**	**$ 1.3**	**-**	**$ 114.9**	**(2.73)**	**0**	**$ 14.4**	**(258.2)**	**0**	**$ -**	**$ 129.4**
Below-the-line Classes																		
GRLF and Mersey Contract	-	$ -	$ -							-	$ -	-	$ -	$ -	0	0	0	**$ -**
LED Capital Costs	-	$ -	$ 0.4							-	$ 0.4	-	$ -	$ -	0	0	0	**$ 0.4**
Total	**-**	**$ -**	**$ 0.4**							**-**	**$ 2.0**	**-**	**$ -**	**$ -**	**0**	**0**	**0**	**$ 0.4**
Total In-Province	**-**	**$ -**	**$ 100.6**	**-**	**$ -**	**$ 13.4**	**-**	**$ -**	**$ 1.3**	**-**	**$ 115.3**	**(2.7)**	**$ -**	**$ 14.4**	**(258.2)**	**$ -**	**$ -**	**$ 129.8**
Exports	**-**	**$ -**	**$ -**	**-**	**$ -**	**$ -**	**-**	**$ -**	**$ -**	**-**	**$ -**	**-**	**$ -**	**$ -**	**-**	**$ -**	**$ -**	**$ -**
Total Electric Revenue	**-**	**$ -**	**$ 100.6**	**-**	**$ -**	**$ 13.4**	**-**	**$ -**	**$ 1.3**	**-**	**$ 115.3**	**(2.7)**	**$ -**	**$ 14.4**	**(258.2)**	**$ -**	**$ -**	**$ 129.8**
Misc. Revenues[2]			**$ 0.6**			**$ -**			**$ -**		**$ 0.6**			**$ -**			**$ -**	**$ 0.6**
Total Revenues			**$ 101.3**			**$ -**			**$ -**		**$ 116.0**			**$ -**			**$ -**	**$ 130.4**

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights

(2) Per kWh charge is not applicable as the class is made up of a number of rates

NON-CONFIDENTIAL

Request IR-75:

Reference: Ex. N-3(viii)(C), 5 OE-01A – CONFIDENTIAL Attachment 1 pdf Page 2/28

(a) Is the Point Tupper Biomass plant to be operated as a must run unit or will it be dispatched as part of an economic merit order?

(b) Please explain why the Point Tupper Biomass plant is not shown in the Strategist output.

Response IR-75:

(a) The Point Hawkesbury Biomass plant is forecast to be operated as a must-run unit.

(b) The Point Hawkesbury Biomass plant is included in transaction purchases – “TRANS PURCH” in Strategist output.

REDACTED

Request IR-76:

Reference: Ex. N-3(viii)(C), 8 OIA – CONFIDENTIAL – Attachment 3, p.498

(a) Please confirm that the average heat rate shown includes start up fuel. If this cannot be confirmed please discuss what is and what is not reflected in the average heat rate calculation.

(b) Please explain how the variable operation and maintenance cost (VAR O&M CST) for each unit was determined. Was a unit variable cost input into Strategist or did the program calculate it from other information?

(c) Please explain how the fixed cost for each unit was calculated.

(d) Please explain why the fixed costs at Lingan 1 and 2 are the same as in NSPI's 2012 General Rate Application Fuel Update (August 31, 2011) when the evidence states that seasonal operation of the Lingan units is one of the ways to reduce fixed costs (Ex. N-2, pdf Page 7/159, Lines 1-6).

(e) Please reconcile the variable Operation & Maintenance expenses and the fixed costs shown in the Strategist runs with the cost used to determine overall revenue requirements.

(f) Please reconcile the fixed cost and variable O&M costs with the OM&G costs used in the calculation of OATT charges (e.g., Ex. N-3(i)(C), DE-03-DE-04, Appendix L, Attachment 4, pdf Page 360/556).

Response IR-76:

REDACTED

(a) In accordance with the FAM Plan of Administration, we use 3-year average of actual achieved unit heat rates, adjusted for specific changes in operation or configuration. These heat rates include the start-up fuels, and all other operating factors of generating units.

(b) Variable operating costs were calculated outside of Strategist. The FAM Plan of Administration states the following in regards to Variable O&M costs:

> 1. Unit Variable Operation and Maintenance (O&M) Costs
> The incremental operating and maintenance costs will be calculated based on a simple average of the last three years.[1]

The calculation for annual steam turbine unit variable operating costs is based on Section III of the attached Maritime Energy Pricing Guidelines from November 1995. Section III Appendix 2, equations 2 and 4 are specified for NS Power coal-fired and oil-fired units. The factors from equation 4 are also applied for the gas-fired steam turbine units.

Please refer to Confidential Attachment 1.

(c) The fixed costs seen in the 08-0E-01A Attachment 3 of the Application were not used in this study. The figures are placeholders for other unrelated Strategist studies which would require these figures to be updated. In the framework of Fuel and Purchased Power Strategist studies, the fixed costs are not used by the software when optimizing dispatch. Forecasted fixed unit operating costs are dealt with elsewhere in the filing.

(d) Please refer to response (c).

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[1] NSPI Fuel Adjustment Mechanism, Plan of Administration, NSUARB-NSPI-P-887, October 15, 2008, Appendix B, page 12.

REDACTED

(e) Please refer to response (c) for details regarding fixed costs displayed in Strategist output. Variable operating costs are used in Strategist in order to determine optimal unit dispatch order. Variable operating costs used in Strategist are expressed in $/MWh and are presented below:

PT ACONI	[redacted]
LINGAN	[redacted]
PT TUPPER	[redacted]
TRENTON	[redacted]
TC 123	[redacted]
TC - CC 6	[redacted]
CT	[redacted]

(f) The variable operating costs presented pertain only to generating units, and when multiplied by the unit forecasted MWh output, represent a part of the overall operating cost. Please refer to response (c) and (e).

CONFIDENTIAL (Attachment Only)

Request IR-77:

Reference: Ex. N-3(viii)(C), OE-10-OE-11, Attachment 1, pdf Page 181/185, Line 28

Please provide the calculation of CCA for each of the years 2012, 2013 (present and proposed) and 2014 (present and proposed).

Response IR-77:

Please refer to Partially Confidential Attachment 1 for the calculation of Capital Cost Allowance (CCA) for each of the years 2012 and 2014. Please refer to CA-41 for the 2013 calculation. The calculations are the same for both present and proposed rates.

[redacted]

2014 CCA Schedule ($M)						
		Opening		Available		Closing
Class	**Rate**	**Balance**	**Additions**	**for CCA**	**CCA**	**Balance**
1	4%	1,120.9	4.8	1,126	44.9	1,080.8
1A	6%	60.2	-	60	3.6	56.6
2	6%	465.0	-	465	27.9	437.1
3	5%	7.9	-	8	0.4	7.5
8	20%	19.7	6.4	26	4.6	21.5
10	30%	23.2	8.0	31	8.2	23.0
12	100%	1.9	3.5	5	3.6	1.8
17	8%	530.0	43.2	573	44.1	529.1
45	45%	0.1	-	0	0.0	0.1
50	55%	6.7	2.8	9	4.5	5.0
47	8%	266.4	81.4	348	24.6	323.2
42	12%	0.1	-	0	0.0	0.1
43.2	50%	16.1	-	16	8.1	8.1
41	25%	0.1	-	0	0.0	0.1
	Sub Total	2,518.4	149.9	2,668.3	174.5	2,493.9
Cumulative Eligible Capital	7%	48.5	3.4	51.9	3.6	48.3
	Total	**2,566.9**	**153.4**	**2,720.2**	**178.1**	**2,542.1**

Less: CCA on non-regulated assets	**(2.1)**
Regulated CCA	**176.0**

Note 1: For class 43.2, the opening balance is lower than the prior year's ending balance due to an opening balance adjustment relating to the income tax treatment of the Nova Scotia Energy Tax credit earned in the prior year.

NON-CONFIDENTIAL

Request IR-78:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 OE-O1A Confidential Attachment 1

Is it NSPI's intention to incorporate biomass price and usage data under solid fuel in these tables?

Response IR-78:

Yes, biomass price and usage has been included under solid fuel in these tables.

NON-CONFIDENTIAL

Request IR-79:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 OE-O1A Confidential Attachment 1, p. 2, 10 etc.

Is it correct to assume that "Point Tupper Biomass" is a reference to Port Hawkesbury?

Response IR-79:

Yes, the reference is meant to refer to the Port Hawkesbury biomass facility.

REDACTED

Request IR-80:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 OE – O1C Confidential Attachment 2, p. 1

a) Please explain the ocean freight assumptions which form the basis for the calculation of the 2013 and 2014 ocean freight transportation forecast.

b) Please explain why total ocean freight costs from 2012 to 2013 are [redacted] [redacted] of the 2012 level but [redacted] [redacted] of 2012 levels.

c) Please explain the basis for the [redacted]

d) Please explain the basis for the LS imported coal price [redacted]

Response IR-80:

(a) The following assumptions were employed in calculating the 2013 and 2014 freight costs:

(i) For freight providers that are contracted through until the end of 2014, yearly Consumer Price Index (CPI) increases were assumed to be [redacted].

(ii) SSY was approached to supply indicative 2013 and 2014 [redacted] for estimation purposes only. For consistency, demurrage estimates were also based on typical yearly [redacted].

REDACTED

(iii) Where possible, it was assumed that gearless self-bulkers could be used to transport coal to Point Tupper marine terminal, reducing the overall freight costs.

(iv) It was assumed that the 2013 forward price of HFO 2.2 percent was appropriate for estimating both the price of 2013 and 2014 bunker fuel. Otherwise, the 2013 forward prices for IFO 180, IFO 380, and MDO were used in the estimation of marine freight fuel costs for both 2013 and 2014.

(b) The 2012 forecast projects that approximately 87 percent of ocean freight costs are attributable to imported coal, and that approximately 13 percent of ocean freight costs are from delivery of petroleum coke. The 2013 forecast projects that approximately [redacted] [redacted] of ocean freight costs are for imported coal, and that approximately [redacted] of ocean freight costs are for petroleum coke. Although the overall 2013 ocean freight costs are [redacted] of the 2012 costs, a significantly higher percentage of these costs are attributed to petcoke, rather than imported coal. This explains why the reduction in total ocean freight costs does not match the reduction in generation from imported coal.

(c) The reasons for an increase in freight costs for Lingan and Point Aconi from 2013 to 2014 are as follows:

(i) NS Power currently has freight contracts for the shipment of Power River Basin (PRB) coal through the great lakes. These contracts incorporate an annual [redacted] from year to year.

(ii) The indicative freight rates supplied by SSY for the transport of low-sulphur coal to the International Pier [redacted] than those of 2013 for the load ports in which the imported coal is loaded.

REDACTED

(iii) As for the delivery of petcoke, the indicative 2014 pricing supplied [redacted] than those of 2013, [redacted] the estimated freight costs for delivery in 2014.

(d) Please refer to OE-01K Attachments 1 and 2 of the Application, which show the assumptions used in the forecast pricing of open low sulphur coal for 2013 and 2014. Price differences between contracted coal for 2013 and 2014 also contribute to the overall difference between the 2013 and 2014 forecast price for low sulphur coal.

NON-CONFIDENTIAL

Request IR-81:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 OE-O1E Confidential Attachment 1, p. 1

Please update this summary of fuel contracts to May 31, 2012

Response IR-81:

This information will be available in the fuel forecast update at the end of August with data updated as of June 30, 2012.

NON - CONFIDENTIAL

Request IR-82:

Reference: Exhibit N-2, Evidence 1 DE-03-DE-04 OE-O1J Confidential Attachment 1, p. 1; Confidential Attachment 2, p. 1

Please update the information in these tables to May 31, 2012

Response IR-82:

This information will be available in the fuel forecast update at the end of August with data updated as of June 30, 2012.