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**Request IR-283:**

**With reference to Application, Appendix 6.03, page 17 and Appendix 6.05, Figures 5 and 6:**

**(a) Please explain the relationship between the "Financial Assumptions" found on page 17 of Appendix 6.03 of the Application and the $905 million transmission upgrade costs referred to in lines 11-13 on page 124 of the Application and shown in Figures 6 of Appendix 6.05 of the Application. Please provide all calculations, including all supporting spreadsheets (with original excel formulas intact) and other documents related to the transmission upgrade costs used for the Other Imports alternative.**

**(b) Please confirm that the $663M (2015$) capital cost includes the $385 million for upgrades shown on the line labeled NB-HQ#3 in Figures 6 of Appendix 6.05 of the Application or explain what cost to Nova Scotia has been assumed for upgrades to the HQ-NB interface.**

**(c) Please confirm that the "NB-HQ#3" upgrades are those needed for a 500 MW firm delivery from HQ as shown in Figure 5 of Appendix 6.05.**

**(d) If not, please explain what level of service can be attained with the "NB-HQ#3" upgrades and compare that to the level of service that can be attained with the "NB-HQ#2" upgrades.**

**(e) Please confirm that, according to Schedule 5 of the ECA, energy that is being delivered that is above the Nova Scotia Block Associated Capacity is non-firm and therefore subject to curtailment including the requirement to deliver Capacity to other Nalcor customers.**

**(f) Please explain why the Other Imports alternative includes costs for 500 MW of firm transmission when the Maritime Link will only provide firm transmission for the Nova Scotia Block Associated Capacity.**

Response IR-283:

(a) The $905M transmission upgrade cost corresponds to calculations for the 2015 NPV Nova Scotia Tariff costs provided by WKM Energy Consultants. Please refer to CA IR-58, Attachment 1 Electronic for the detailed spreadsheet. The tab to be referenced is "HQ500Adj". NSPML uses values presented on this tab in deriving the inputs for the Other Import case for modeling in Strategist. Specifically, the amount for capital to be recovered in Nova Scotia rate base and the cost of transmission service through New Brunswick for the capacity and energy. Please refer to Attachment 1 for a visual reference of the values on this tab that were used as inputs to the Other Import case. The calculations by WKM Energy Consultants also include an NPV estimation of the cost of transmission service through New Brunswick for the capacity and energy and an amount for "end effects". NSPML's Strategist model calculates these amounts. As per Appendix 6.03, page 17, the $676M as spent, nominal capital is based on the WKM report, and is derived as follows:

a. NS Tariff Share of $150M represents the share of NB-NS#1 that would be borne by NS.

b. NS Tariff Share of $292M represents the share of NB-HQ#3 that would be borne by NS.

c. This totals $442M. For the Other Import analysis, this amount was increased by a factor of 50 percent due to:

i. O & M/OATT costs (25 percent as per Appendix 6.05 of the Application).

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ii. AFUDC (10 percent).

The remaining 15 percent is comprised of the combination of the following:

iii. Uncertainty surrounding the actual estimate amount.

iv. Uncertainty surrounding the amount of direct assignment Nova Scotia would see.

v. To represent a potential P90 similar to the Maritime Link P90 capital cost for the Ventyx analysis.

d. $292M + $150M = $442M X 1.5 = $663 M, 2015$, escalated by 1 percent per year to represent the as spent dollars that will become part of rate base, or $676M to rate base upon commercial operation.

(b) Confirmed. Please see (a) above for the amount of expected allocation to NS.

(c) Confirmed.

(d) Please refer to (c).

(e) Confirmed.

(f) The Maritime Link also provides approximately an additional 80 MW of firm transportation in addition to the NS Block for a total of 250 MW firm. The Maritime Link has a capacity of 500 MW. It provides NS Power with 170 MW Firm supply purchase from Nalcor. Nalcor owns the remaining transmission rights to the capacity on the

Maritime Link so there is a dedicated path for Nalcor supply to Nova Scotia. When Nova Scotia purchases additional energy from Nalcor, Nalcor has a path to deliver it. The Other Import Alternative includes 165 MW firm supply and up to 335 MW of economy energy. In order to ensure economy energy can be delivered to Nova Scotia, a firm path needs to be secured by suppliers whereas Nalcor will have the rights of the Maritime Link (above the NS Block firm rights). Please also see the response to CanWEA IR-54 (b).

# Marshall Report – Capital Cost

Appendix A – Page 23

| NSPI Transmission Costs Under NB OATT | | | | | | |
|---|---|---|---|---|---|---|
| Case HQ500Adj - 500 MW HQ to NS with Direct Assignment | | | | | | |
| | | 2003/04 | 2008/09 | 2015/16 | 2050/51 | |
| **Capital upgrades ($M)** | | | | | | |
| Project | | Base | IPL/NRI | HQ/NS | | NS Direct |
| Total Cost (NS#1+HQ#3) | 1 | | 75 | 1050 | | |
| NS Tariff Share | 2 | | | 150 | | 292.0 |
| Net NB Tariff Cost | 3=1-2-Direct | | 75 | 608 | | |
| **Revenue Requirement ($M)** | | | | | | |
| Transmission Service Rev Req | 4 (Note) | 80.5 | 91.0 | 140.8 | 219.7 | |
| **Usage (MW)** | | | | | | |
| Network | 5 | 2100 | 2100 | 1900 | 2262 | |
| Long term firm | 6 | 720 | 1080 | 1580 | 1580 | |
| Short term equivalent | 7 | 300 | 250 | 200 | 200 | |
| Total usage | 8=5+6+7 | 3120 | 3430 | 3680 | 4042 | |
| **Tariff ($/kW-yr)** | | | | | | |
| Transmission Service | 9=4/8*1000 | 25.8 | 26.5 | 38.3 | 54.4 | |
| **Nova Scotia Tariff costs ($M)** | | | | | | |
| NS Firm Reservation (MW) | 10 | | | 500 | 500 | |
| Annual charge | 11=9*10/1000 | | | 19.1 | 27.18 | 27.18 |
| 2015 NPV | 12=npv(11) | | | 315.5 | | |
| Direct Assignment Charge | 13=Direct*125% | | | 365.0 | | |
| NSPI Tariff Additions | 14=2*125% | | | 187.5 | | |
| End Effects Share | 15=3*10%*Share | | | 41.9 | | |
| Total 2015 NPV cost | 16=12+13+14+15 | | | 910.0 | | 68.95% |
| **Other Tx Customer Costs** | | | | | | |
| Total Reservations | 17 | 3120 | 3430 | 3180 | 3542 | |
| Annual charge | 18=17*9/1000 | | | 121.7 | 192.6 | |
| Annual Base Tariff Cost | 19 | | | 99.4 | 155.2 | |
| Share of Upgrade Costs | 20=18-19 | | | 22.2 | 37.35 | |
| NPV Share | 21=npv(22) | | | 391.0 | | |
| End Effects Share | 22=3*10%*Share | | | 18.9 | | |
| Total 2015 NPV Cost | 23=21+22 | | | 409.9 | | 31.05% |
| Total Additional Cost vs Base | 24 | | | 1313 | | |
| Total Tariff Recovery (35 yrs) | 25=16-15+21 | | | 1259 | 95.9% | |
| Tariff End Effect (Year 35-45) | 26=3*10% | | | 60.8 | | |
| Total Cost Recovery | 27=25+26 | | | 1320 | 100.5% | |

## Capital Cost

$292 M NS Direct (NB-HQ#3)
$150 M NS Tariff Share (NB-NS#1)
$442 M

$442M * 50% (Future O&M/OATT Costs, AFUDC, Uncertainty regarding actual capital estimate amount and NS Direct Assignment percentage, P90 Capital Cost)

= $663M 2015$

= **$676M 2017$**

Note: The $910M corresponds to the $905M in Figure 6. It varies slightly due to iterations performed to allocate costs between NS and Others at the prescribed percentages in Figure 6.



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# Marshall Report – Tariff Cost

Appendix A – Page 23

**NSPI Transmission Costs Under NB OATT**

**Case HQ500Adj - 500 MW HQ to NS with Direct Assignment**

| | | 2003/04 | 2008/09 | 2015/16 | 2050/51 | |
|---|---|---|---|---|---|---|
| **Capital upgrades ($M)** | | | | | | |
| Project | | Base | IPL/NRI | HQ/NS | | NS Direct |
| Total Cost (NS#1+HQ#3) | 1 | | 75 | 1050 | | |
| NS Tariff Share | 2 | | | 150 | | 292.0 |
| Net NB Tariff Cost | 3=1-2-*Direct* | | 75 | 608 | | |
| **Revenue Requirement ($M)** | | | | | | |
| Transmission Service Rev Req | 4 *(Note)* | 80.5 | 91.0 | 140.8 | 219.7 | |
| **Usage (MW)** | | | | | | |
| Network | 5 | 2100 | 2100 | 1900 | 2262 | |
| Long term firm | 6 | 720 | 1080 | 1580 | 1580 | |
| Short term equivalent | 7 | 300 | 250 | 200 | 200 | |
| Total usage | 8=5+6+7 | 3120 | 3430 | 3680 | 4042 | |
| **Tariff ($/kW-yr)** | | | | | | |
| Transmission Service | 9=4/8*1000 | 25.8 | 26.5 | 38.26 | 54.4 | |
| **Nova Scotia Tariff costs ($M)** | | | | | | |
| NS Firm Reservation (MW) | 10 | | | 500 | 500 | |
| Annual charge | 11=9*10/1000 | | | 19.1 | 27.18 | 27.18 |
| 2015 NPV | 12=npv(11) | | | 315.5 | | |
| Direct Assignment Charge | 13=*Direct*125%* | | | 365.0 | | |
| NSPI Tariff Additions | 14=2*125% | | | 187.5 | | |
| End Effects Share | 15=3*10%**Share* | | | 41.9 | | |
| Total 2015 NPV cost | 16=12+13+14+15 | | | 910.0 | | 68.95% |
| **Other Tx Customer Costs** | | | | | | |
| Total Reservations | 17 | 3120 | 3430 | 3180 | 3542 | |
| Annual charge | 18=17*9/1000 | | | 121.7 | 192.6 | |
| Annual Base Tariff Cost | 19 | | | 99.4 | 155.2 | |
| Share of Upgrade Costs | 20=18-19 | | | 22.2 | 37.35 | |
| NPV Share | 21=npv(22) | | | 391.0 | | |
| End Effects Share | 22=3*10%*Share | | | 18.9 | | |
| Total 2015 NPV Cost | 23=21+22 | | | 409.9 | | 31.05% |
| Total Additional Cost vs Base | 24 | | | 1313 | | |
| Total Tariff Recovery (35 yrs) | 25=16-15+21 | | | 1259 | 95.9% | |
| Tariff End Effect (Year 35-45) | 26=3*10% | | | 60.8 | | |
| Total Cost Recovery | 27=25+26 | | | 1320 | 100.5% | |

## Total Tariff Cost

### Transmission Service

$38.26/kW-yr
X 500 MW-yr
X 1000 kW/MW
$19.13 M 2015$

$19.71 M 2018$ (esc. by 1%/yr)

### Ancillary Service

$5.11/kW-yr
X 500 MW-yr
X 1000 kW/MW
$2.56 M 2015$

$2.63 M 2018$ (esc. by 1%/yr)

$19.71 M + $2.63M
**= $22.345M/yr 2018$**

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**NSPI Transmission Costs Under NB OATT**

**Base Case - No Upgrades to the NB System**

| | | 2003/04 | 2008/09 | 2015/16 | 2049/50 |
|---|---|---|---|---|---|
| **Capital upgrades ($M)** | | | | | |
| Project | | Base | IPL/NRI | HQ/NS | |
| Total Cost (NS#1+HQ#3) | 1 | | 75 | 0 | |
| NS Tariff Share | 2 | | | 0 | |
| Net NB Tariff Cost | 3=1-2 | | 75 | 0 | |
| **Revenue Requirements ($M)** | | | | | |
| Transmission Service Rev Req | 4=1-2-3 | 80.5 | 91.0 | 99.4 | 155.2 |
| *Ancillary Services* | | | | | |
| System Control (Sched 1) | 5 | 4.5 | 7.9 | 9.1 | 18.1 |
| Voltage Control (Sched 2) | 6 | 5.6 | 6.3 | 7.2 | 14.4 |
| Total Compulsory AS | 7=5+6 | 10.1 | 14.2 | 16.3 | 32.5 |
| **Usage (MW)** | | | | | |
| Network | 8 | 2100 | 2100 | 1900 | 2262 |
| Long term firm | 9 | 720 | 1080 | 1080 | 1080 |
| Short term equivalent | 10 | 300 | 250 | 200 | 200 |
| Total usage | 11=8+9+10 | 3120 | 3430 | 3180 | 3542 |
| **Tariffs ($/kW-yr)** | | | | | |
| Transmission Service | 12=4/11*1000 | 25.8 | 26.5 | 31.3 | 43.81 |
| Ancillary Services | 13=7/11*1000 | 3.24 | 4.13 | 5.11 | 9.18 |
| **Transmission Customer Costs ($M)** | | | | | |
| Total Reservations | 14=11 | | | 3180 | 3542 |
| Tariff Annual charges | 15=14*12/1000 | | | 99.4 | 155.2 |
| Uniform Escalation from 2015 | 15 | | | 1.300% | |
| 2015 NPV Tariff Cost | 16=npv(15) | | | 1705 | |

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**Request IR-284:**

**With reference to responses CA/SBA IR-7 and IR-8, referencing the response to CanWEA IR-26, please confirm that absent the development of Muskrat Falls, the only expanded wind or hydro generation resources available to Nova Scotia via Maritime Link until 2041 would be the recall energy from Upper Churchill Falls.**

Response IR-284:

Once the Maritime Link is completed, Nalcor has 300 MW of recall energy available from the Upper Churchill, which it could send to market through existing routes and the Maritime Link.

In addition, please see MPA IR-22 which explains the incremental resources which are and could be available in NL prior to 2041.

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**Request IR-285:**

**With reference to response CA/SBA IR-12, please provide the following reports from the list provided:**

**(a) #1 – "Subsea Cable Corridor Survey – Cabot Strait" December 21, 2011, Fugro Geological Surveys, Inc., including Appendices and Enclosures.**

**(b) #4 – "Sediment Transfer Study" June 8, 2012, CBCL Limited.**

**(c) #8 - "Ice Risk Analysis for Cabot Strait Cable Crossing" December 2012, CCore.**

**(d) #11 - "Cable Burial Study" August 2012, Intecsea.**

**(e) #13 – "Interpretation of Recent Survey Data Cabot Strait" February 10, 2012, AMGC.**

Response IR-285:

(a) Please refer to Confidential Attachments 1 through 37.

(b) Please refer to Confidential Attachment 38.

(c) Please refer to Confidential Attachment 39.

(d) Please refer to Confidential Attachment 40.

(e) Please refer to Confidential Attachment 41.

**CA/SBA IR-285**

**Attachments 1 to 41**

**have been removed due to confidentiality.**

**NON-CONFIDENTIAL**

**Request IR-286:**

**With reference to response CA/SBA IR-17, please clarify whether the "Route Geophysical and Geotechnical Report (Fugro)" referenced in the response is the same as document #1 listed under the response to IR-12. Please provide a copy of the "Route Geophysical and Geotechnical Report" by Fugro.**

Response IR-286:

Yes, the referenced report in the response of CA/SBA IR-017 is the same as document #1 listed under the response to CA/SBA IR-012.

Please refer to SBA IR-285 Attachments 1 through 37.

**Request IR-287:**

**With reference to response CA/SBA IR-22(a) that Strategist can use dynamic programming to determine optimal retirement dates for resources:**

**(a) Please explain fully the cost and revenue logic that determines the year in which to retire an existing generation unit.**

**(b) Please provide a table of all existing NSPI thermal generation units with columns indicating the first year and the last year that retirement was considered in the analysis runs with Strategist. If different first and last available years assumptions were used across the runs, repeat the table for each run conducted.**

Response IR-287:

(a) Ventyx documentation is proprietary and confidential. General information concerning Strategist may found at the Ventyx website: http://www.ventyx.com/en/enterprise/business-operations/business-products/strategist

A product overview may be found at: http://www.ventyx.com/~/media/files/brochures/strategist-data-sheet.ashx?download=1

(b) Please refer to CA/SBA IR-295 (a). In all cases, all thermal units except Lingan 1 and Lingan 2 were considered for retirement in years 2020 through to 2040. Please refer to CA/SBA IR-323 for details around the Lingan 1 and Lingan 2 retirements.

**Request IR-288:**

**With reference to response CA/SBA IR-24(c) that Ventyx documentation is proprietary and confidential, please provide a description of Strategist modeling methods at a publicly-available level in accordance with the type of information requested in IR-24(c).**

Response IR-288:

General information concerning Strategist may found at the Ventyx website:
http://www.ventyx.com/en/enterprise/business-operations/business-products/strategist

Ventyx describes Strategist functionality in the product brochure available on the vendor's website:
http://www.ventyx.com/~/media/files/brochures/strategist-data-sheet

**CONFIDENTIAL (Attachments only)**

**Request IR-289:**

**With reference to response CA/SBA IR-29, please provide the input data, assumptions, and the quantitative results for each robustness scenario evaluated that are the basis for the statement "All robustness scenarios tested showed the Maritime Link to be the lowest long-term cost Alternative." Provide the same 112 page output report for each robustness scenario in electronic TXT file format, as was provided for one case in response to CA/SBA IR-277 Confidential Electronic Attachment 1. Provide the input data and assumptions for each robustness scenario in electronic TXT file or Excel file format.**

Response IR-289:

Please refer to Confidential Attachments 1 through 42 for the Strategist output and input reports for each robustness scenario referenced in CA/SBA IR-29. The attachments and their associated case are given in the table below.

Please refer to Attachment 43 for a table comparing the study period costs of the Maritime Link to the Other Import and Indigenous Wind for the robustness scenarios that were tested.

Please refer to Attachment 44 for the resource plan for the Indigenous Wind Low Load case with Additional Retirements.

**CONFIDENTIAL (Attachments only)**

| Output Reports | Input Reports | Case | Revised Input |
|---|---|---|---|
| Attachment 1 | Attachment 22 | ML Base Load Case - Base ESAI Gas Prices | Synapse IR-33 Att 1 |
| Attachment 2 | Attachment 23 | OI Base Load Case - Base ESAI Gas Prices | Synapse IR-33 Att 1 |
| Attachment 3 | Attachment 24 | Wind Base Load Case - Base ESAI Gas Prices | Synapse IR-33 Att 1 |
| Attachment 4 | Attachment 25 | ML Base Load Case - High ESAI Gas & High ESAI Energy Prices | Synapse IR-33 Att 1 |
| Attachment 5 | Attachment 26 | OI Base Load Case - High ESAI Gas & High ESAI Energy Prices | Synapse IR-33 Att 1 |
| Attachment 6 | Attachment 27 | Wind Base Load Case - High ESAI Gas & High ESAI Energy Prices | Synapse IR-33 Att 1 |
| Attachment 7 | Attachment 28 | ML Base Load Case - Low ESAI Gas & Low ESAI Energy Prices | Synapse IR-33 Att 1 |
| Attachment 8 | Attachment 29 | OI Base Load Case - Low ESAI Gas & Low ESAI Energy Prices | Synapse IR-33 Att 1 |
| Attachment 9 | Attachment 30 | Wind Base Load Case - Low ESAI Gas & Low ESAI Energy Prices | Synapse IR-33 Att 1 |
| Attachment 10 | Attachment 31 | ML Low Load Case - Base ESAI Gas Prices | Synapse IR-33 Att 1 |
| Attachment 11 | Attachment 32 | OI Low Load Case - Base ESAI Gas Prices | Synapse IR-33 Att 1 |
| Attachment 12 | Attachment 33 | Wind Low Load Case - Base ESAI Gas Prices | Synapse IR-33 Att 1 |
| Attachment 13 | Attachment 34 | OI Base Load Case - High Gas and High ESAI Energy Price - Firm Import price based on High ESAI Energy | Synapse IR-33 Att 1 |
| Attachment 14 | Attachment 35 | OI Base Load Case - Low Gas and Low ESAI Energy Price - Firm Import price based on Low ESAI Energy | Synapse IR-33 Att 1 |
| Attachment 15 | Attachment 36 | OI Base Load Case - High ESAI Gas and High ESAI Energy Price - Firm Import price based on High ESAI Energy | Synapse IR-33 Att 1 |
| Attachment 16 | Attachment 37 | OI Base Load Case - Low ESAI Gas and Low ESAI Energy Price - Firm Import price based on Low ESAI Energy | Synapse IR-33 Att 1 |
| Attachment 17 | Attachment 38 | OI Base Load Case - Low Transmission Capital | $442 M ($2015) |
| Attachment 18 | Attachment 39 | OI Base Load Case - High Transmission Capital | $820 M ($2015) |
| Attachment 19 | Attachment 40 | Wind Low Load Case - Additional Retirements | Attachment 44 |
| Attachment 20 | Attachment 41 | ML Base Load Case - Formula ROE Approach | 2015: 10.08%<br>2016: 10.53%<br>2017-2040: 10.68% |
| Attachment 21 | Attachment 42 | OI Base Load Case - Formula ROE Approach | 2015-2040: 10.68% |

**CA/SBA IR-289**

**Attachments 1 to 42**

**have been removed due to confidentiality.**

**Robustness Scenarios**

| Base Load Cases - Base ESAI Gas Prices | Maritime Link (ML) | Other Import | Additional Cost versus ML Alternative | Indigenous Wind | Additional Cost versus ML Alternative |
|---|---|---|---|---|---|
| Study Period NPV $M | 15,481 | 15,939 | 458 | 16,347 | 866 |

| Base Load, High ESAI Gas & High ESAI Energy Prices | Maritime Link (ML) | Other Import | Additional Cost versus ML Alternative | Indigenous Wind | Additional Cost versus ML Alternative |
|---|---|---|---|---|---|
| Study Period NPV $M | 16,844 | 17,314 | 470 | 17,835 | 992 |

| Base Load, Low ESAI Gas & Low ESAI Energy Prices | Maritime Link (ML) | Other Import | Additional Cost versus ML Alternative | Indigenous Wind | Additional Cost versus ML Alternative |
|---|---|---|---|---|---|
| Study Period NPV $M | 14,371 | 14,850 | 479 | 15,235 | 864 |

| Low Load Cases - Base ESAI Gas Prices | Maritime Link (ML) | Other Import | Additional Cost versus ML Alternative | Indigenous Wind | Additional Cost versus ML Alternative |
|---|---|---|---|---|---|
| Study Period NPV $M | 12,184 | 12,708 | 524 | 12,516 | 331 |

| Base Load Cases - High Gas and High ESAI Energy Price | Maritime Link (ML) | Other Import (Firm Import based on High ESAI Energy ) | Additional Cost versus ML Alternative |
|---|---|---|---|
| Study Period NPV $M | 18,238 | 18,826 | 588 |

| Base Load Cases - Low Gas and Low ESAI Energy Price | Maritime Link (ML) | Other Import (Firm Import based on Low ESAI Energy) | Additional Cost versus ML Alternative |
|---|---|---|---|
| Study Period NPV $M | 14,767 | 15,180 | 413 |

| Base Load Cases - High ESAI Gas and High ESAI Energy Price | Maritime Link (ML) | Other Import (Firm Import based on High ESAI Energy) | Additional Cost versus ML Alternative |
|---|---|---|---|
| Study Period NPV $M | 16,844 | 17,649 | 806 |

| Base Load Cases - Low ESAI Gas and Low ESAI Energy Price | Maritime Link (ML) | Other Import (Firm Import based on Low ESAI Energy) | Additional Cost versus ML Alternative |
|---|---|---|---|
| Study Period NPV $M | 14,371 | 14,635 | 265 |

| Base Load Cases | Maritime Link (ML) | Other Import- Low Transmission Capital | Additional Cost versus ML Alternative | Other Import- High Transmission Capital | Additional Cost versus ML Alternative |
|---|---|---|---|---|---|
| Study Period NPV $M | 16,209 | 16,238 | 29 | 16,623 | 413 |

| Low Load Cases | Maritime Link (ML) | Indigenous Wind - Additional Retirements | Additional Cost versus ML Alternative |
|---|---|---|---|
| Study Period NPV $M | 12,221 | 13,210 | 989 |

| Base Load Cases | Maritime Link (ML) Formula ROE | Other Import Formula ROE | Additional Cost versus ML Alternative |
|---|---|---|---|
| Study Period NPV $M | 16,294 | 16,525 | 231 |

**Resource Plan**

| | Wind Low Load<br>with Additional Retirements<br>with Integration Costs |
|---|---|
| **2015** | Lin #2 retire |
| **2016** | |
| **2017** | |
| **2018** | |
| **2019** | Wind 250 MW<br>CT 50 MW<br>Lin #1 retire |
| **2020** | |
| **2021** | |
| **2022** | |
| **2023** | |
| **2024** | |
| **2025** | |
| **2026** | |
| **2027** | |
| **2028** | |
| **2029** | |
| **2030** | CC 250MW<br>Coal Unit retire |
| **2031** | |
| **2032** | |
| **2033** | Coal Unit retire |
| **2034** | |
| **2035** | Coal Unit retire |
| **2036** | |
| **2037** | CT 100 MW |
| **2038** | CT 100 MW<br>Coal Unit retire |
| **2039** | Wind 250 MW re-powered |
| **2040** | |
| Planning NPV $B | 9.200 |
| Study NPV $B | 13.210 |

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**Request IR-290:**

**With reference to response CA/SBA IR-30(a), notwithstanding NSPI's "typical" use of a 25-year planning period, why did NSPI not make an exception for this study and use a Strategist Planning Period that ends no earlier than the end of the Maritime Link 35 year contract term in 2052? In your response, please justify why it is appropriate to calculate a NPV for an alternative that basically assumes history repeats itself over the latter one-third of the 35 year contract.**

Response IR-290:

The majority of inputs are not forecasted out for the full 25 years so to extend the planning period has limited value given that most inputs are escalated by inflation by that point in time. This is the same treatment used for operating cost components in the end effects period; please refer to SBA IR-293 part (c). In terms of the capital costs, the Maritime Link would continue to depreciate to the end of its 35 year life in the end effects period. There would then be periodic replacement-in-kind of the asset in perpetuity. These operating and capital costs are appropriately reflected in the Study period NPV.

Non-financial inputs such as the load and the emission limits are assumed to continue at the 2040 values in the end effects period to reflect the greater uncertainty of these forecasts and assumptions beyond the long term 25 year view.

**NON-CONFIDENTIAL**

**Request IR-291:**

**With reference to response CA/SBA IR-30(b), page 1, line 18 to page 2, line 2, please tabulate for each alternative (Maritime Link, Other Imports, and Indigenous Wind) and for each case (Base Load, Low Load, High Power and Gas Cost, and Low Power and Gas Cost) the contributions to NPV costs for the Planning Period and for the Study Period of capital costs for the Maritime Link, other transmission projects, wind generation, added gas-fired combined cycle and simple cycle combustion turbine plants, and any other capital investments affecting the extended study period.**

Response IR-291:

Please refer to Synapse IR-54 Attachment 1. This attachment shows the contribution to capital costs made by each addition in each year of the planning period. The Capital costs for the High Power and Gas Prices and Low Power and Gas Prices are the same as the for Base Load cases. The same Base Load resource plans were used in these sensitivities; the resource plans were re-dispatched with the high/low power and gas prices which changes only the operating costs.

Strategist determines the end effects costs internally as a single net present value calculation and adds it to the planning period costs to give the study period costs. Please refer to SBA IR-331 part (b) for the output reports for these cases. The Study Period Plan Comparison in the last page of the output reports show the end effects value calculated by Strategist for each case. The study period costs of the Maritime Link case have been adjusted to account for the 35 year depreciation life of the Project versus the 50 year operating life. Please refer to SBA IR-334 (c) for the derivation of the adders.

**NON-CONFIDENTIAL**

**Request IR-292:**

**With reference to response CA/SBA IR-30(b) first paragraph, for clarification of the definition of the study period provided, please confirm that it would be more accurate to add the word "period" after each of the two mentions of "end effects", or otherwise provide a more clear definition.**

Response IR-292:

Yes, the definition of study period is:

Study Period = Planning Period + End Effects Period.

**NON-CONFIDENTIAL**

**Request IR-293:**

**With reference to response CA/SBA IR-30(b) second paragraph, please explain fully the infinite period end effects calculations:**

**(a) Confirm that no costs are included for retirement of existing generation and transmission assets or for the capital and operating costs of replacement assets for existing assets that would be retired during the end effects period.**

**(b) Confirm that 2040 load was assumed for each year of the infinite end effects period, or otherwise explain.**

**(c) Explain fully what assumptions are made to project fuel prices, energy prices, capacity prices, and other cost and revenue components during the infinite end effects period.**

Response IR-293:

(a) Confirmed.

(b) Confirmed.

(c) In the end effects period all cost and revenue items escalate at the implied rate calculated from the final two years of the planning period. In this analysis the escalation rate for each cost and revenue item would be the percent increase from 2039 to 2040.

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**Request IR-294:**

**With reference to response CA/SBA IR-30(b) last sentence (page 1 line 28 to page 2 line 2) regarding the need to apply an end effects method to not bias selection of resources, and Response CA/SBA IR-27 Attachment 7, page 4 of 18, first two sentences of first new paragraph:**

> **The systems were simulated in detail for the study period of 2015 through 2040 with the capital costs of each new generation resource charged at its escalating economic carrying cost. This approach treated projects of differing lives within the study period on a level playing field and eliminated the need to conduct an end effects analysis beyond 2040.**

**(a) Please confirm or otherwise explain that Strategist has the cited alternative method for handling end effects, which is to not include an end effects period and instead only include real levelized annual capital costs for the portion of new resource lives that are within the Planning Period.**

**(b) Please explain why this simpler, alternative method for handling the end effects issue was not utilized by Ventyx for the Maritime Link application study, either for the 2015 through 2040 Planning Period used, or for a longer planning period ending 2052, that would encompass the full Maritime Link contract life.**

Response IR-294:

(a) Yes, Strategist can represent capital costs using escalating economic carrying charges which eliminates the need for an end effects analysis beyond the planning period.

(b) The annual stream of declining revenue requirements method was used in the analysis for this Application. This method assumes the asset's value decreases over time as the asset depreciates and is preferred over the economic carrying charge method because it is more representative of the actual annual costs of the Company and more closely matches the economics of a regulated asset. The declining revenue requirements method also allows for further cost analyses such as the determination of rate impacts. This method of analysis has been used by NS Power as part of the business case for numerous capital projects and has been accepted by the UARB in the past.

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**Request IR-295:**

**With reference to response CA/SBA IR-32(a-b):**

**(a) Please explain fully how NSPI's selection of unit retirement dates for each Strategist run interacted with Strategist resource addition decisions. Was an iterative process used in order to identify a good or optimal resource plan within the confines of each Strategist alternative case?**

**(b) Please explain whether the method of handling retirements provides an exact or approximately optimal (good) resource plan, given the Strategist model's objective function and constraints, within the confines of each Strategist alternative case.**

Response IR-295:

(a) NS Power forecasted unit retirements outside of the Strategist model. An iterative process was used to determine the number and timing of retirements as other forms of generation or firm imports were added to the system to comply with environmental requirements. For each case a preliminary Strategist optimization without retirements was examined to see which units had reduced capacity factors. Possible unit retirements were examined to ensure the planning reserve margin was maintained if those low capacity factor units were to be retired. These retirements were included in a subsequent Strategist optimization to determine the effect of the retirements on the resource plan in terms of resources added and cost. In all cases, all thermal units except Lingan 1 and Lingan 2 were considered for retirement in years 2020 through to 2040. Please refer to CA/SBA IR-323 for details around the Lingan 1 and Lingan 2 retirements.

(b) Although the retirements were not determined within the model, a Strategist optimization was performed with those retirements as inputs and the resulting resource plan is the optimal plan given those inputs.

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**Request IR-296:**

**With reference to response CA/SBA IR-37(b) line 19, please explain fully what is meant by "no option." For example, was a 10% of output option not available through the negotiation process, considered but deemed inferior, or not considered.**

Response IR-296:

Please see SBA IR 20 (c). It should also be pointed out that the goal of negotiations with Nalcor was to displace one coal unit, which was considered the optimal amount at 20 percent. Anything less than one unit would require the unit to stay running. More than one unit, but less than a full additional unit, would also have the same effect.

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**Request IR-297:**

**With reference to response CA IR-44(a) and Attachment 1:**

**(a) Which, if any, of the identified pumped storage projects were included in either the pre-screening of alternatives or any of the Strategist modeling cases?**

**(b) If any pumped storage projects were included Strategist modeling cases, what were their assumed characteristics?**

**(i) Working storage capacity ($m^3$).**

**(ii) Head (m).**

**(iii) Full load operation hours.**

**(iv) Maximum generation capacity (MW).**

**(v) Maximum pumping capacity (MW).**

**(vi) Turn around efficiency.**

**(vii) Capital Cost.**

**(viii) Ancillary services capabilities.**

- **Ramp rate on discharge (MW/sec).**
- **Ramp rate pumping (MW/sec).**

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Response IR-297:

(a-b) Pumped storage or load control was assumed to be a component of the capital costs associated with the integrating wind and not modeled specifically as referenced in part (b), therefore the data requested is not available.

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**Request IR-298:**

**With reference to response CA IR-44(a) and Attachment 2 (CONFIDENTIAL):**

**(a) Were any of the pumped hydro storage options at Wreck Cove described in Attachment 2 Confidential considered as part of the Indigenous Wind Alternative in the Strategist cases modeled, and if not, why not?**

**(b) If one or more Wreck Cove pumped storage project options were considered, please provide the following for each:**

**(i) Option identification.**

**(ii) The amount of indigenous wind capacity that this pumped storage facility would support in terms of reserve capacity, frequency control, and avoidance of wind energy curtailment.**

**(iii) Assumed earliest available year of commercial operation.**

**(iv) Assumed capital cost.**

**(v) Assumed amortization life.**

Response IR-298:

(a-b) The requirements for back-up of intermittent resources were determined outside of the model and included as a capital cost in the Indigenous Wind cases. They included a component of pumped storage but not a specific project. Please refer to Synapse IR-18.

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**Request IR-299:**

**With reference to response CA/SBA IR-47(c), despite lack of ramp rate constraints in the Strategist model, does it enforce minimum net operating capacity constraints during on-line periods?**

Response IR-299:

Yes, the Strategist model enforces minimum and maximum net operating capacity constraints during on-line periods.

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**Request IR-300:**

**With reference to response CA/SBA IR-51(b), please also provide copies of other planning studies, as requested, or confirm that only the cited IRPs have dealt with the issue of back-up for intermittent resources.**

Response IR-300:

Please refer to CA IR-44 Confidential Attachment 2.

Please refer to the Hatch wind integration study for NS Department of Energy available at the following link:

http://www.gov.ns.ca/energy/resources/EM/Wind/NS-Wind-Integration-Study-FINAL.pdf

NS Power has examined the experiences of other jurisdictions many of which are discussed in papers cited in the Bibliography of Appendix 6.02.

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**Request IR-301:**

**With reference to response CA/SBA IR-58, please clarify what is meant by "unable."**

Response IR-301:

The prehearing discovery process allows for discovery and disclosure of information that is within the possession and/or control of the party that has received the Information Request; that is, information and analysis that already exists. The process does not require new analysis or work to be undertaken, although hearing participants are able to undertake their own analysis based upon existing information or data.

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**Request IR-302:**

**With reference to response CA/SBA IR-64(c), please confirm our understanding that Ventyx had no role in formulating the assumptions, data, run settings, and any other inputs to the modeling of the resource alternatives and market scenarios, or otherwise explain.**

Response IR-302:

In performing the optimizations, Ventyx would have adjusted run settings such as boundary conditions to allow the model to determine a set of feasible combinations.

In some cases, Ventyx would also have taken input assumptions and converted them into a format that could be used within Strategist. For example, the revenue requirement profiles for the three alternatives would have been put in a format that Strategist uses internally.

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**Request IR-303:**

**With reference to response CA/SBA IR-66(f-g) as it relates to request part (g), please explain whether in addition to planning capacity constraints, Strategist also models for each time block:**

**(a) On-line operating reserve capacity constraints.**

**(b) Minimum generation constraints for a class of units, such as representing NPSI's minimum steam unit generation constraint.**

Response IR-303:

(a) Yes. Strategist considers online spinning reserve requirement constraints.

(b) Strategist does not explicitly model a minimum steam generation constraint. The minimum steam generation constraint was considered external to Strategist in order to estimate curtailment and the resulting reduction of incremental wind generation capacity factor which was provided to Strategist as an input.

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**Request IR-304:**

**With reference to response CA/SBA IR-68(d) page 2 lines 7-8, please clarify whether the sentence means that Strategist is unable to model the minimum steam generation commitment constraints by time block.**

Response IR-304:

The question appears to reference CA/SBA IR-69 (d). As described in CA/SBA IR-303 (b), Strategist does not explicitly model minimum steam generation constraints.

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**Request IR-305:**

**With reference to response CA/SBA IR-71(q), please clarify "decrease" should be replaced with "multiplied", or otherwise explain.**

Response IR-305:

Correct. The wording should reflect a factor of 80 percent. The word should be “multiplied”.

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**Request IR-306:**

**With reference to response CA/SBA IR-75(e):**

**(a) With reference to Synapse IR-018 Attachment 2 - please confirm that the Indigenous Wind runs for the case with integration costs includes $300 million dollars for energy storage.**

**(b) CA/SBA-75 Attachment 1 presents annual detailed capital cost results differences for the Indigenous Wind runs for the cases with and without integration costs. Please provide a similar table for operating costs or confirm that the same Strategist run results were used for Indigenous Wind runs for the cases with and without integration costs.**

**(c) If the same Strategist run results were used, please explain why a $300 million dollars energy storage investment was assumed to make no difference in the need for wind curtailment or the dispatch of other generators.**

Response IR-306:

(a) Confirmed. NS Power included $150 million for energy storage in the Indigenous Wind low load case. $300 million was included in the Indigenous Wind base load case.

(b) Yes, the operating costs were the same in the runs with and without wind integration costs.

(c) It may be correct to assume a reduction in wind generation curtailment with the development of pumped storage facilities. However, we have not included the operating efficiency of the pump cycle which is similar to the curtailment levels and likely higher.

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**Request IR-307:**

**With reference to Response CA/SBA IR-82(b), please explain whether the Other Import alternative could have been scaled down to the same GWh size as for the Maritime Link.**

Response IR-307:

The Other Import capability is identical to the Maritime Link, both at 500MW capability. Prior to losses, the Other Import is actually smaller than the Maritime Link (963.6 GWh versus 986 GWh).

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**Request IR-308:**

**In your response to CA/SBA IR-91, you acknowledge that there is no specific mention of the Nova Scotia Power Network Upgrades in the Nova Scotia Transmission Utilization Agreement ("NSTUA"):**

**(a)** **Please explain why no specific mention of these upgrades is made in the NSTUA whereas they feature prominently in the Application, on pages 143-145, Section 8.2.1 and NSPML is seeking UARB confirmation that these projects are currently necessary for the Nalcor Surplus Energy to have a path through the Province.**

**(b)** **In your response you refer to Section 2.2. (d) in the NSTUA. Please explain why this Section is sufficient to cover the provision of the upgrades whereas it is simply noting that, absent the occurrence of Forgivable Events, the transmission capacity of the Emera Facilities and the Emera Point-to-Point Transmission Service shall be sufficient to allow transmission of the Nalcor Maximum Transmission Capacity Level.**

Response IR-308:

(a-b) The NSTUA requires NS Power (via the Agency and Services Agreement) to provide a transmission path for an amount of energy equivalent to the Nalcor Maximum Transmission Capacity Level. The important aspect to Nalcor is that a path exists, while the importance to NS Power is to provide that path in accordance with the NSTUA. This path will be achieved through a combination of utilizing existing infrastructure, fleet redispatch and/or network upgrades. No commitment was made for specific upgrades in the NSTUA, as it is in Nova Scotia's best interests for NS Power to retain the optionality as to how it will provide the transmission path in question.

**Request IR-309:**

**In your response to CA/SBA IR-93 (e-f) you note that, "…Absent the Nalcor Surplus Energy, reliability upgrades to the system aren't necessary. However, any upgrade to the system will provide an inherent reliability benefit to customers. The benefit results from greater capacity and enhanced system equipment…"**

**(a) Is it your position that the Nova Scotia Power Network Upgrades should be classified as reliability upgrades to the Nova Scotia System?**

**(b) Please explain why the Nova Scotia Power Network Upgrades should not be classified as economic upgrades to the Nova Scotia System, intended to facilitate economic transfers by Nalcor, since by definition the Nalcor Surplus Energy is not part of the Nova Scotia Block.**

**(c) Please explain your statement that "…any upgrade to the system provides an inherent reliability benefit to customers..." Please also explain why "…greater capacity and enhanced system equipment…" necessarily provides a reliability benefit to Nova Scotia Customers.**

**(d) Please reconcile your statement that, "…any upgrade to the system provides an inherent reliability benefit to customers..." with your statement made in your response to CA/SBA IR-34 (a) that "…Transmission through New Brunswick does not provide any additional reliability…"**

Response IR-309:

(a) Please refer to the Application in Section 8.2.1 for a justification for the potential upgrades. A transmission service request System Impact Study (SIS) is in progress, and preliminary results are found in McMaster IR-02 Confidential Attachment 1. The

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Network Upgrades in the Application are provided to show the type and magnitude of the expenditures, subject to completion of the SIS. The transmission service request system impact study will provide additional information and will be included in the regulatory approval requested for the projects when and if they are deemed necessary. It is anticipated that the transmission revenues over the life of the project will offset the costs of the capital upgrades and redispatch.

(b) Please see NSUARB IR-137 (a) (ii).

(c) Additional transmission capacity and improved equipment will allow for greater flexibility when using the transmission system, such as during maintenance. Although not "necessary" for the operation of existing and potential renewable generation, Network Upgrades will help minimize out-of-merit generation dispatch and potential curtailment of renewable energy resources that have interconnected using Energy Resource Network Service. In the absence of the Maritime Link, the upgrade to L-6513 would allow for a higher setting of the Import Monitor Special Protection System (SPS). Similarly, the reconfiguration of L-8004 and L-7005 will increase arming level of the 345 kV SPS, reducing risk of tripping thermal generation in Cape Breton.

(d) Response to CA/SBA IR-34 (a) was meant to reflect the lack of reliability benefits from generation resources from the west, which are elsewhere committed. Response CA/SBA IR-34 (b), on the other hand, highlights the benefits of increased tie-line capacity and reinforced transmission capacity within New Brunswick, since such reinforcements would greatly reduce the risk of Nova Scotia islanding and subsequent loss of firm load.

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**Request IR-310:**

**With reference to your response to CA/SBA IR-108, please provide in GWh/year the energy attributable to the Supplemental Energy Block for two scenarios: (i) at Muskrat Falls (i.e. inclusive of transmitssion losses), and (ii) at Woodbine (i.e. net of transmission losses).**

Response IR-310:

The Energy and Capacity Agreement (Appendix 2.03 to the Application) and in particular Schedule 4 of that Agreement provides for the calculation of Supplemental Energy to be calculated as delivered to Nova Scotia, net of losses. The current estimate of transmission losses inherent in that calculation is 9.2 percent. In the body of the Application it was noted that the Supplemental Energy as delivered to Nova Scotia (net of transmission losses) was estimated to be 240,000 megawatt-hours per year (pages 79 and 120). The equivalent in gigawatt hours is 240. That amount was the calculation of Supplemental Energy at the time the alternatives analysis was performed. Since then, we have updated the calculation and it currently is estimated to be approximately 252 gigawatt-hours per year for the first five years. That amount (252 GWh) was used in the calculation of the weighted average price of energy as outlined in Figure 4-4 and in the response to NSUARB IR-37. Pursuant to Article 3 of Schedule 4 of the Energy and Capacity Agreement, the calculation of Supplemental Energy will be finalized at a date determined therein which is close to first commercial power.