CONFIDENTIAL (Attachment Only)

Request IR-78:

Please provide the confidential versions of the documents requested in CA IR 10 to 14.

Response IR-78:

Please refer to the following attachments for the referenced documents. A link to the UARB's website with the matter number was included in the initial response and constitutes an adequate response. Parties can and have entered documents from prior proceedings into evidence for various later proceedings. Confidential versions of the documents are maintained on the UARB's repository.

- Confidential Attachment 1: CA IR-10 part (a) - 2013 GRA OP-05 Attachment 1.
- Confidential Attachment 2: CA IR-10 part (b) – 2013 GRA OP-08 Attachment 1.
- Confidential Attachment 3: CA IR-10 part (c - n) – NSPI 2013 Fuel Forecast Update for FAM and 2013 GRA.
- Partially Confidential Attachment 4: CA IR-12 part (a) – 2013 ACE SBA IR-38 Attachment 1.
- Partially Confidential Attachment 5: CA IR-12 part (b) – 2013 ACE NSUARB IR-15.

The document requested in CA IR-11 was provided. The response to CA IR-13 indicates that the requested new analysis has not been performed in preparing the Application. There are no previously filed materials to include as attachments for that question. CA IR-14 requests information included in CA IR-10 Attachment 3.

CA IR-78 Attachment 1 has been removed due to confidentiality.

CA IR-78 Attachment 2 has been removed due to confidentiality.

CA IR-78 Attachment 3 has been removed due to confidentiality.

Thermal Generating Unit	Summer Capacity MW	Winter Capacity MW	Fuel Type (Supplemental)	In-Service Date	2013 Forecast Heat Rate Btu/KWh	2011 Capacity Factor	2010 Capacity Factor	2009 Capacity Factor
Lingan 1	153	153	Coal (Pet Coke, Heavy Fuel Oil)	1979	[redacted]	71%	64%	78%
Lingan 2	153	153	Coal (Pet Coke, Heavy Fuel Oil)	1980	[redacted]	59%	65%	67%
Lingan 3	153	153	Coal (Pet Coke, Heavy Fuel Oil)	1983	[redacted]	57%	69%	70%
Lingan 4	153	153	Coal (Pet Coke, Heavy Fuel Oil)	1984	[redacted]	64%	72%	80%
Point Aconi	171	171	Coal, Pet Coke	1994	[redacted]	77%	81%	85%
Point Tupper	152	152	Coal (Pet Coke, Heavy Fuel Oil)	1987	[redacted]	49%	88%	82%
Trenton 5	135	150	Coal (Pet Coke, Heavy Fuel Oil)	1969	[redacted]	50%	57%	54%
Trenton 6	157	157	Coal (Pet Coke, Heavy Fuel Oil)	1991	[redacted]	89%	77%	86%
Tufts Cove 1	81	81	Natural Gas, Heavy Fuel Oil	1965	[redacted]	76%	82%	38%
Tufts Cove 2	93	93	Natural Gas, Heavy Fuel Oil	1972	[redacted]	77%	76%	57%
Tufts Cove 3	147	147	Natural Gas, Heavy Fuel Oil	1976	[redacted]	68%	51%	53%
Tufts Cove 4	47	49	Natural Gas	2003	[redacted]	63%	52%	45%
Tufts Cove 5	47	49	Natural Gas	2005	[redacted]	38%	39%	58%
Tufts Cove 6	47	49	Natural Gas	2011	[redacted]	1%	N/A	N/A

PARTIALLY CONDIFENTIAL

Request IR-15:

With respect to the long term investment strategy for the combustion turbine fleet, referenced on page 15:

(a) Please provide a table identifying each LFO combustion unit, their net capacity, years when they were put in service, their capacity factors in each of previous 5 years, as well as the remaining service life if no additional capital is injected.

(b) Please quantify and compare the cost of a unit of energy produced by each of the above facilities with the cost of energy produced by other generation facilities.

(c) What were the annual capital and maintenance expenditures on each of these units in last 5 years?

(d) Please provide the forecasted annual capital and maintenance expenditures on each of these units for years 2012 - 2016.

(e) Does NSPI plan to retire any of these units in the next 5 years? Please elaborate.

(f) Is there any other option except to refurbish all these units? Please elaborate.

(g) Please provide a justification that the proposed refurbishment of all these units represents the most cost effective alternative, and explain why they should not be decommissioned.

(h) It appears that a number of these units have not run for a number of years. Please explain why NSPI decided to refurbish these units now?

(i) Please provide copies of all studies and reports, prepared in last 5 years, which discusses refurbishment, retirement, or replacement of these units.

Response IR-15:

(a) Please refer to the table below.

Unit	Commission	Capacity	Heat Rate	Capacity Factors (%)				
		MW	Btu/kWh	2007	2008	2009	2010	2011
Burnside 1,2,3	**1976**	30	[redacted]	2.151	0.673	4.354	2.352	1.405
Victoria Junction	**1975 (Unit 1)** **1976 (Unit 2)**	30	[redacted]	0.212	0.048	0.498	0.251	0.156
Tusket	**1971**	25	[redacted]	0.233	0.000	0.102	0.120	0.003

Remaining service life is currently under assessment. Generally, these units are nearing the end of their design life. It is anticipated that there will be major component replacement (shafts, disks and other cyclic fatigue susceptible parts) and/or entire machine replacements. Ongoing assessment will guide long-term planning.

(b) The liquid fuelled Fleet (Victoria Junction, Burnside and Tusket) is significantly more expensive to operate than coal units or gas generation. This difference varies in comparison to the various generating units and the fuel costs at any given time, however, the liquid fuelled generators are several times more expensive than NS Power alternatives.

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(c) Please refer to the table below for Operating and Maintenance costs. This table includes Burnside, Victoria Junction, Tusket and the LM6000 units (Tufts Cove Units 4 and 5).

2008 Actual ($)	2009 Actual ($)	2010 Actual ($)	2011 Actual ($)	2012 Q3 Forecast ($)
1,157,785	1,196,203	1,218,045	1,383,942	1,749,481

Please refer to the table below for a summary of capital investment in the units (not including routine work). The table represents only Burnside, Victoria Junction and Tusket.

2008 Actual ($)	2009 Actual ($)	2010 Actual ($)	2011 Actual ($)	2012 Forecast ($)	2013 ACE ($)
115,799	115,943	186,454	223,394	1,984,777	2,581,490

(d) At this time there are no planned significant changes to the current operating or capital investments for these units. The long-term assessment study is currently underway and due to be completed in Q2 2013. The results of this study, in combination with any other efforts, such as the wind integration study, will determine future capital and operating for the long-term.

(e) Long-term assessment is currently underway. This study will guide any future retirement decisions.

(f) Refurbishment, while an option, is not currently planned for all these units. Other options include:

- Replacement with a dual-fuel combustion turbine unit
- Replace with gas combustion turbine

- Combination of refurbishment and replacement

(g) Full refurbishment of these units is not currently proposed. CI 42807, the Free Turbine Overhaul project submitted to the Board for approval on September 28, 2012, includes only those units found to be out of compliance on the free turbine inlet guide vanes cracking limits. To date, there are four Burnside units affected, and three units included in the scope of the project (the project excludes Unit 4). This project does not represent full scale refurbishment, but are investment to enable the units to continue to generate and provide for system security and black start capability.

The units cannot be decommissioned due to the requirement to serve. The units are required for black start, and are critical power generation reserve to meet North American Electric Reliability Corporation (NERC) requirements when needed. They are also utilized for Volt-Ampere Reactive (VAR) support. When the unit is in synchronous mode, the engine is de-coupled from the generator and VAR support is accomplished through the generator spinning independently. Additionally the units must be sustainable in order to support the planned 2015 retirement of Lingan 2.

(h) Only Burnside Unit 4 has not run in a number of years. The remaining 3 Burnside units, Victoria Junction and Tusket have run for VAR support, black start and spinning reserve. The functioning Burnside units required free-turbine refurbishment because cracks were found in the inlet blades and the units need to run to meet system demands, spinning reserve, black-start, VAR support, and to support the future shut-down of Lingan 2.

(i) Please refer to Confidential Attachment 1, and Confidential Attachment 2.

The remainder of CA-IR-78 Attachment 5 has been removed due to Confidentiality.

NON-CONFIDENTIAL

Request IR-79:

Please provide the data graphed in CA IR-30 Attachment 2 in Excel-readable form.

Response IR-79:

CA IR-30 Attachment 2 is the output format of the power system simulator PSS®E from Siemens Power Technologies International. The only output options for these plots are PostScript/PDF format and graphical display on a computer screen. There is no output of these simulations compatible with Excel.

NON-CONFIDENTIAL

Request IR-80:

The responses to CA IR 15 to 19 and 22 to 24 neither provided the requested information nor claimed that NSPI has no such information. Please provide any documents in NSPI's possession that are responsive to these requests.

Response IR-80:

As NSPML explained in response to CA IRs 15 to 19, these questions are better directed to the author of the report, which is a publicly available document. NSPML is neither the author nor sponsor of the report. NSPML's evidence in support of the Maritime Link, in accordance with the Regulations, is contained in its Application.

Requests 22 to 24 pertain to the Renewable Energy Integration Study. As explained in the responses, that study is not yet completed. NS Power intends to file that study with the UARB upon completion, since that filing is a required action item under the 2010 FAM Audit Action Plan.

NON-CONFIDENTIAL

Request IR-81:

Reference response to CA IR-30 Attachment 2(d):

(a) Please provide the calculation leading to the conclusion that "The NS Block will have a capacity factor of about 68 percent." Please provide the capacity value on which this capacity factor computation is based.

(b) Please provide the calculation leading to the conclusion that "Based on Muskrat Falls surplus and the NS Block alone, the capacity factor of the Maritime Link will be 60 percent…"

Response IR-81:

We believe your request to be in reference to the response to EAC IR-4 (d):

(a) The NS Block is delivered for 16 hours per day only. 16 hours / 24 hours = 66.7 percent (approximately 68 percent).

(b) Please refer to NSUARB IR-65. The projected energy available for export from Newfoundland and Labrador, including the NS Block, is roughly 2.96 TWh, or 60 percent of the 4.93 TWh annual production. Accounting for the transmission loss factor, this equates to approximately 2.7 TWh (2,700,000 MWh) available to be delivered to Woodbine, including the NS block. The capacity factor is therefore calculated as: (2,700,000 MWh) / (500 MW x 8760 hours) = 61.4 percent, which is approximately 60 percent.

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Request IR-82:

Reference response to Liberty IR-5:

(a) Please provide the Liberty IR-5 attachments in excel format, with formulae attached.

(b) Please explain how NSPI select the PIRA forecasts, rather than each of the following sources:

- **(i) other commercial forecasts,**
- **(ii) the Energy Information Administration's Annual Energy Outlook reference case, and**
- **(iii) NYMEX forwards.**

(c) Please provide all documentation in the possession of NSPI or NSPML regarding the assumptions and methodology underlying the PIRA gas-price forecast.

(d) Please identify the source of Liberty IR-5 Attachment 2, pages 2 and 3.

(e) Please define and provide the source of the "M&NP Exp" in Liberty IR-5 Attachment 2, page 4.

(f) PIRA has announced that shale gas and other factors "have caused PIRA to lower its longer-term price outlook for both liquids and gas." ("PIRA Energy Group Releases Annual Scenario Planning Guidebook, Forecasting Long-Term Oil and Gas Markets," PRWEB, February 25, 2013) If NSPI or NSPML has access to the PIRA 2013 forecast, please provide the gas and oil forecasts from that document.

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Response IR-82:

(a) Please refer to Confidential Attachments 1 and 2, provided electronically as Excel files.

(b) PIRA was selected because NS Power currently uses PIRA for long term forecasting. Please refer to Liberty IR-4 and PC IR-10.

(c) Please refer to the NS Power Confidential FAM data room, binder titled “PIRA Scenario Planning Service: Annual Guidebook 2012”.

(d) Please refer to Liberty IR-17 and Liberty IR-18.

(e) Please refer to Liberty IR-19.

(f) Please refer to Confidential Attachment 3.

CA IR-82 Attachment 1 has been removed due to confidentiality.

CA IR-82 Attachment 2 has been removed due to confidentiality.

CA IR-82 Attachment 3 has been removed due to confidentiality.

NON-CONFIDENTIAL

Request IR-83:

Regarding Synapse IR-18 Attachment 1:

(a) Please provide the spreadsheet "Integration Cost Estimate Graph (4).xlsx" referenced in cell B3.

(b) Please provide the basis and derivation of the formulae in Synapse IR-18 Attachment 1:

(i) Low Cost = (3356.48*MW*MW-3472222.22*MW+956250000)/1000000
(ii) High Cost = =(636.57*MW*MW+1972222.22*MW-1050625000)/1000000

(c) Please provide all the spreadsheets in the folder "m25ms\My Documents\DataP&P\Planning\Wind\Wind Whitepaper" referenced in Synapse IR-18 Attachment 1.

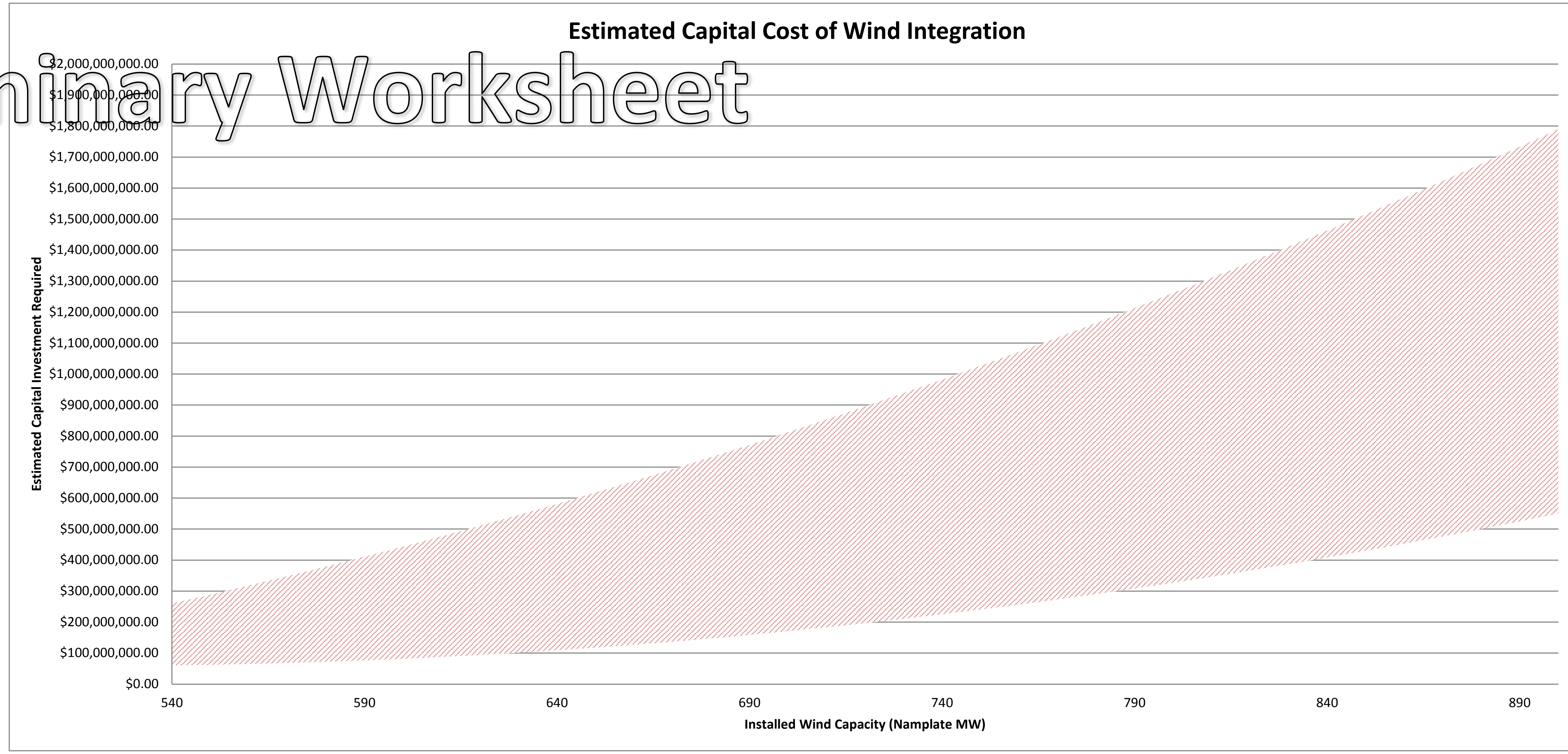
Response IR-83:

(a) The referenced file is Synapse IR-18 Attachment 1.

(b) These are curves selected to fit data points derived from Synapse IR-18 Attachment 2.

(c) Please refer to Attachments 1 to 4, which are spreadsheets found in the specified location and are preliminary in nature.

MW	Cost Low	Cost High
540	$ 60,000,000.00	$ 200,000,000.00
550	$ 61,862,979.00	$ 226,659,646.00
560	$ 64,397,684.80	$ 253,447,795.20
570	$ 67,603,686.60	$ 280,363,258.40
580	$ 71,480,984.40	$ 307,406,035.60
590	$ 76,029,578.20	$ 334,576,126.80
600	$ 81,249,468.00	$ 361,873,532.00
610	$ 87,140,653.80	$ 389,298,251.20
620	$ 93,703,135.60	$ 416,850,284.40
630	$ 100,936,913.40	$ 444,529,631.60
640	$ 108,841,987.20	$ 472,336,292.80
650	$ 117,418,357.00	$ 500,270,268.00
660	$ 126,666,022.80	$ 528,331,557.20
670	$ 136,584,984.60	$ 556,520,160.40
680	$ 147,175,242.40	$ 584,836,077.60
690	$ 158,436,796.20	$ 613,279,308.80
700	$ 170,369,646.00	$ 641,849,854.00
710	$ 182,973,791.80	$ 670,547,713.20
720	$ 196,249,233.60	$ 699,372,886.40
730	$ 210,195,971.40	$ 728,325,373.60
740	$ 224,814,005.20	$ 757,405,174.80
750	$ 240,103,335.00	$ 786,612,290.00
760	$ 256,063,960.80	$ 815,946,719.20
770	$ 272,695,882.60	$ 845,408,462.40
780	$ 290,000,000.00	$ 875,000,000.00
790	$ 307,973,614.20	$ 904,713,890.80
800	$ 326,619,424.00	$ 934,557,576.00
810	$ 345,936,529.80	$ 964,528,575.20
820	$ 365,924,931.60	$ 994,626,888.40
830	$ 386,584,629.40	$ 1,024,852,515.60
840	$ 407,915,623.20	$ 1,055,205,456.80
850	$ 429,917,913.00	$ 1,085,685,712.00
860	$ 452,591,498.80	$ 1,116,293,281.20
870	$ 475,936,380.60	$ 1,147,028,164.40
880	$ 499,952,558.40	$ 1,177,890,361.60
890	$ 524,640,032.20	$ 1,208,879,872.80
900	$ 550,000,000.00	$ 1,240,000,000.00



Wind 540MW Case	Estimated Cost Low ($Millions)	Estimated Cost High ($Millions)
New Gas CT Plant #1	$ 60.00	$ 100.00
New Gas CT Plant #2	$ -	$ 100.00
General Transmission Upgrades	$ -	$ -
Energy Storage	$ -	$ -
Total Capital Costs	**$ 60.00**	**$ 200.00**

Low Load Case

Wind 780MW Case	Estimated Cost Low ($Millions)	Estimated Cost High ($Millions)
New Gas CC Plant #1	$ 60.00	$ 100.00
New Gas CC Plant #2	$ 60.00	$ 100.00
New Gas CC Plant #3	$ -	$ 100.00
General Transmission Upgrades & Tieline	$ 170.00	$ 275.00
Energy Storage	$ -	$ 300.00
Total Capital Costs	**$ 290.00**	**$ 875.00**

Low Load Case (785MW) - Incremental costs for 250MW of wind

	Estimated Cost Low ($Millions)	Estimated Cost High ($Millions)	Estimated Cost Mid ($Millions)
New Gas CC Plant #1	$ -	$ -	$ -
New Gas CC Plant #2	$ 60.00	$ -	$ -
New Gas CC Plant #3	$ -	$ 100.00	$ -
General Transmission Upgrades & Tieline	$ 170.00	$ 275.00	$ 222.50
Energy Storage	$ -	$ 300.00	$ 150.00
Total Capital Costs	**$ 230.00**	**$ 675.00**	**$ 372.50**

Base Load Case

Wind 900+MW Case	Estimated Cost Low ($Millions)	Estimated Cost High ($Millions)
New Gas CC Plant #1	$ 60.00	$ 100.00
New Gas CC Plant #2	$ 60.00	$ 100.00
New Gas CC Plant #3	$ 60.00	$ 100.00
General Transmission Upgrades & Tieline	$ 170.00	$ 540.00
Energy Storage (pumped storage)	$ 200.00	$ 400.00
Total Capital Costs	**$ 550.00**	**$ 1,240.00**

Base Load Case (960MW) - Incremental costs for 425MW of wind

	Estimated Cost Low ($Millions)	Estimated Cost High ($Millions)	Estimated Cost Mid ($Millions)
New Gas CC Plant #1	$ -	$ -	
New Gas CC Plant #2	$ 60.00	$ -	$ -
New Gas CC Plant #3	$ 60.00	$ 100.00	$ -
General Transmission Upgrades & Tieline	$ 170.00	$ 540.00	$ 355.00
Energy Storage (pumped storage)	$ 200.00	$ 400.00	$ 300.00
Total Capital Costs	**$ 490.00**	**$ 1,040.00**	**$ 655.00**

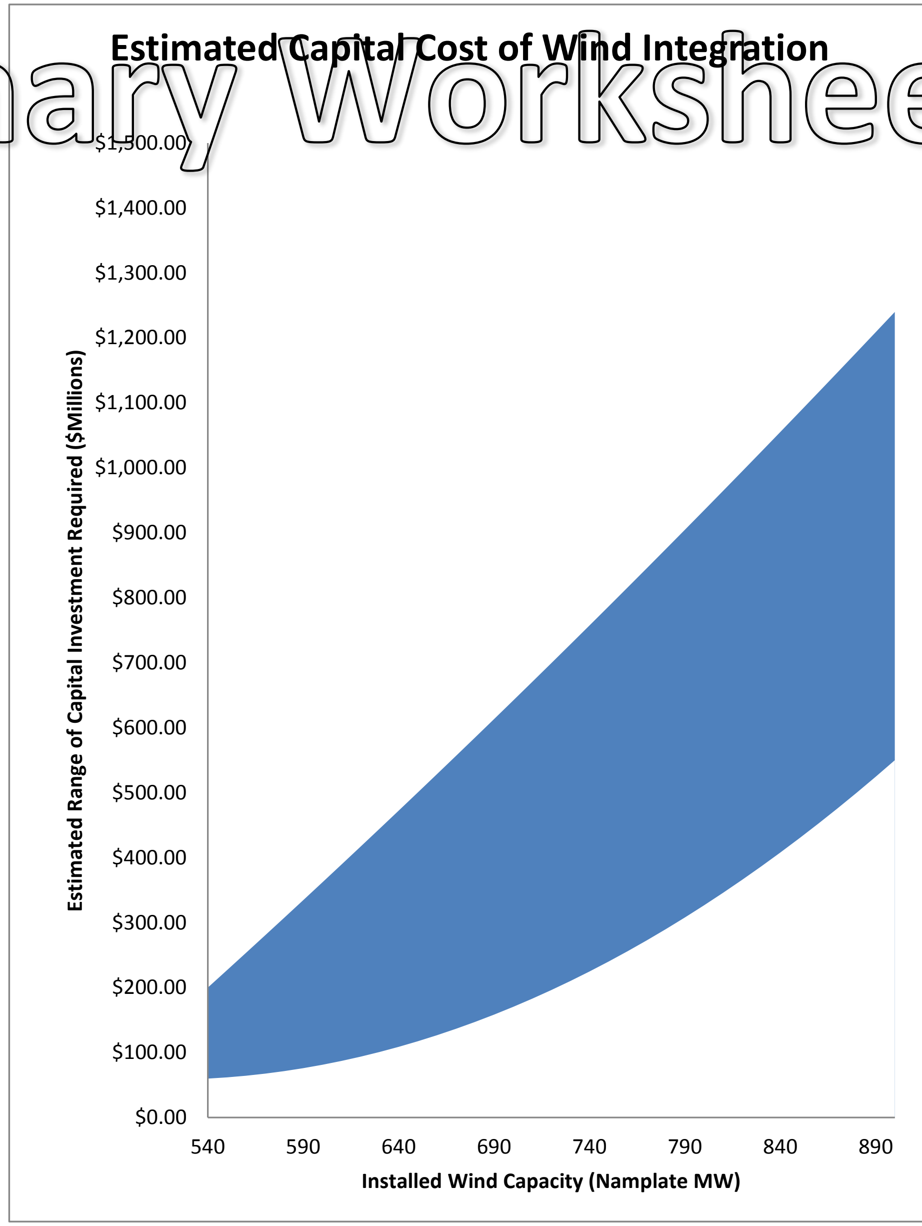
Low Load Case (785MW) - Incremental costs for 250MW of wind

In the Low Load case we are adding a 50MW CT in the resource plan in 2019 for reserve margin. It is assumed that this CT can be run for wind integration purposes and represents either the 50MW CT in the Low cost case or the 100MW CT in the High cost case. Therefore we did not include a CT in the integration costs in the Low Load. Also note that the CC250MW built in 2030 in the Low Load case could be built as only the CT portion in 2019 with a HRSG added in 2030 when it is required for energy/ emissions. We did not advance the cost of the CC250 so we kept the costs on the conservative side. We then took the transmissions costs and Energy storage costs and averaged the low and high cost values to get a mid value that was modeled in Strategist ($372.5M).

Base Load Case (960MW) - Incremental costs for 425MW of wind

In the Base Load case we are adding a 50MW CT in the resource plan in 2019 for reserve margin. It is assumed that this CT can be run for wind integration purposes and represents either the two 50MW CT in the Low cost case or the 100MW CT in the High cost case. Therefore we did not include a CT in the integration costs in the Base Load. Also note that the CC250MW built in 2026 in the Base Load case could be built as only the CT portion in 2019 with a HRSG added in 2026 when it is required for energy/ emissions. We did not advance the cost of the CC250 so we kept the costs on the conservative side. We then took the transmissions costs and Energy storage costs and averaged the low and high cost values to get a mid value that was modeled in Strategist ($655M).

MW	Cost Low		Cost High	
540	$	60.00	$	200.00
550	$	61.86	$	226.66
560	$	64.40	$	253.45
570	$	67.60	$	280.36
580	$	71.48	$	307.41
590	$	76.03	$	334.58
600	$	81.25	$	361.87
610	$	87.14	$	389.30
620	$	93.70	$	416.85
630	$	100.94	$	444.53
640	$	108.84	$	472.34
650	$	117.42	$	500.27
660	$	126.67	$	528.33
670	$	136.58	$	556.52
680	$	147.18	$	584.84
690	$	158.44	$	613.28
700	$	170.37	$	641.85
710	$	182.97	$	670.55
720	$	196.25	$	699.37
730	$	210.20	$	728.33
740	$	224.81	$	757.41
750	$	240.10	$	786.61
760	$	256.06	$	815.95
770	$	272.70	$	845.41
780	$	290.00	$	875.00
790	$	307.97	$	904.71
800	$	326.62	$	934.56
810	$	345.94	$	964.53
820	$	365.92	$	994.63
830	$	386.58	$	1,024.85
840	$	407.92	$	1,055.21
850	$	429.92	$	1,085.69
860	$	452.59	$	1,116.29
870	$	475.94	$	1,147.03
880	$	499.95	$	1,177.89
890	$	524.64	$	1,208.88
900	$	550.00	$	1,240.00

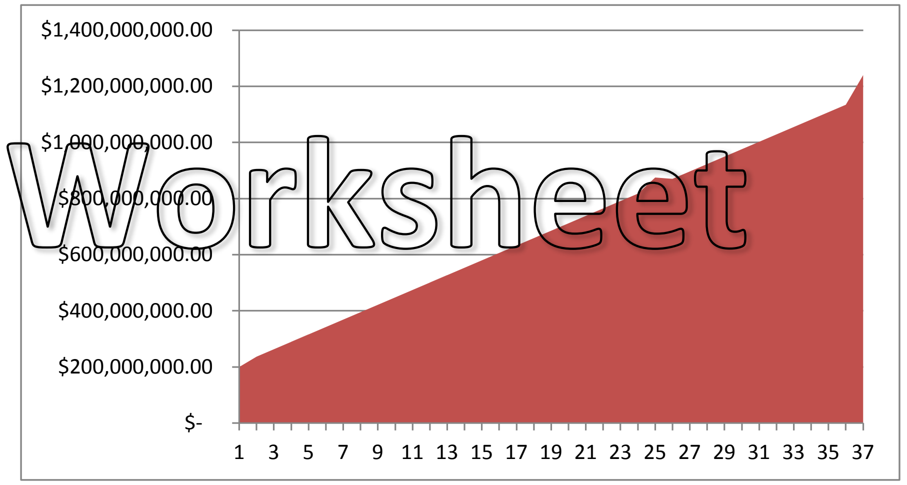


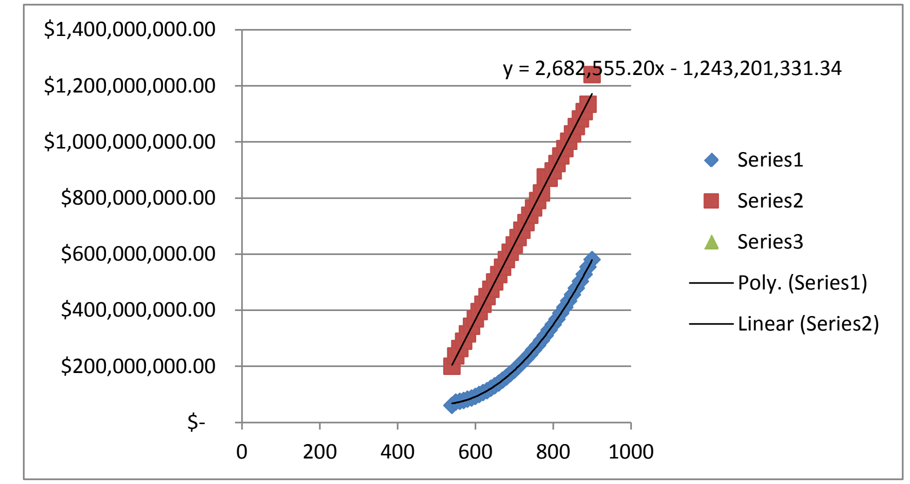
Wind 540MW Case	Estimated Cost Low ($Millions)	Estimated Cost High ($Millions)
New Gas CT Plant #1	$ 60.00	$ 100.00
New Gas CT Plant #2	$ -	$ 100.00
General Transmission Upgrades	$ -	$ -
Energy Storage	$ -	$ -
Total Capital Costs	**$ 60.00**	**$ 200.00**

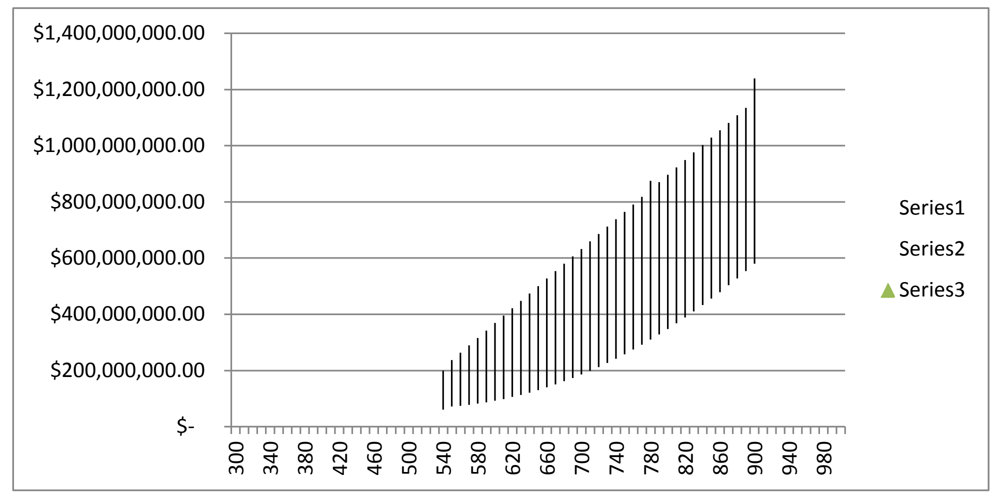
Wind 780MW Case	Estimated Cost Low ($Millions)	Estimated Cost High ($Millions)
New Gas CC Plant #1	$ 60.00	$ 100.00
New Gas CC Plant #2	$ 60.00	$ 100.00
New Gas CC Plant #3	$ -	$ 100.00
General Transmission Upgrades & Tieline	$ 170.00	$ 275.00
Energy Storage	$ -	$ 300.00
Total Capital Costs	**$ 290.00**	**$ 875.00**

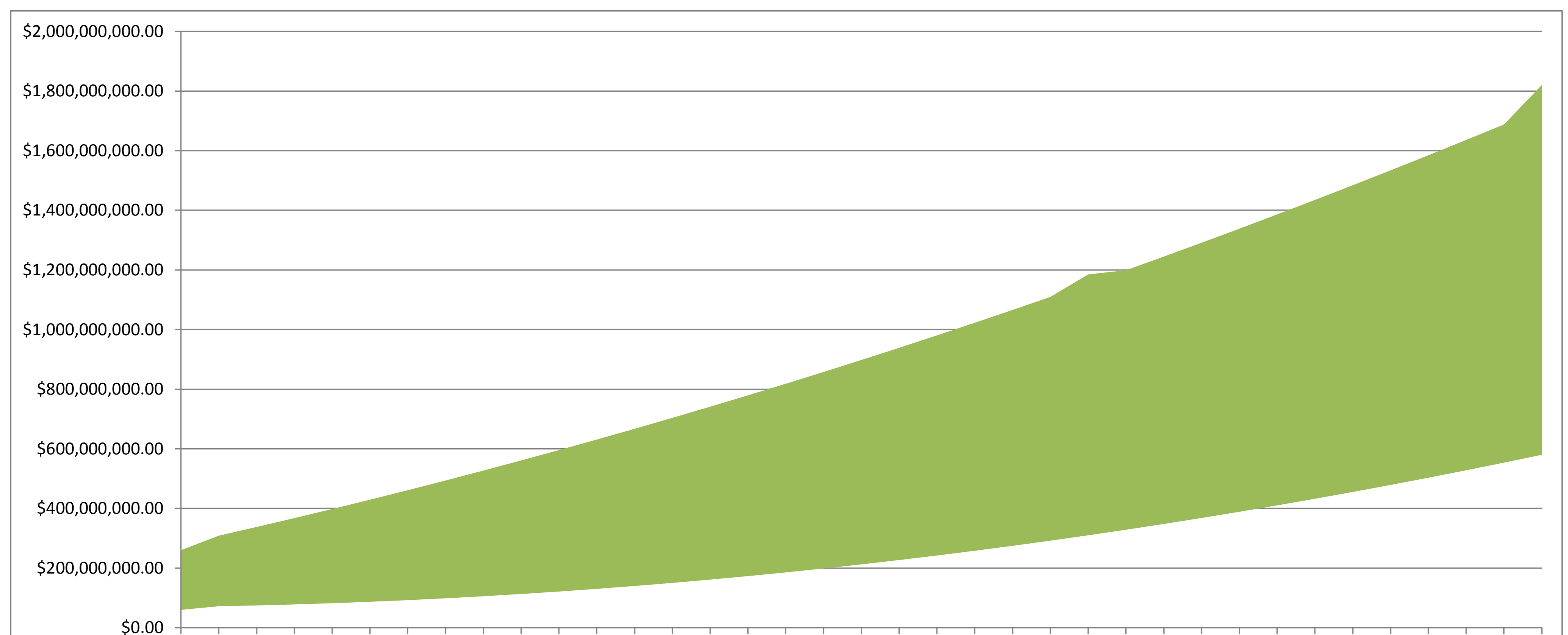
Wind 900+MW Case	Estimated Cost Low ($Millions)	Estimated Cost High ($Millions)
New Gas CC Plant #1	$ 60.00	$ 100.00
New Gas CC Plant #2	$ 60.00	$ 100.00
New Gas CC Plant #3	$ 60.00	$ 100.00
General Transmission Upgrades & Tieline	$ 170.00	$ 540.00
Energy Storage (pumped storage)	$ 200.00	$ 400.00
Total Capital Costs	**$ 550.00**	**$ 1,240.00**

MW	Cost Low	Cost High
300		
310		
320		
330		
340		
350		
360		
370		
380		
390		
400		
410		
420		
430		
440		
450		
460		
470		
480		
490		
500		
510		
520		
530		
540	$ 60,000,000.00	$ 200,000,000.00
550	$ 72,013,218.50	236755951.1
560	$ 74,721,527.20	263154760.6
570	$ 78,124,279.90	289553570.1
580	$ 82,221,476.60	315952379.6
590	$ 87,013,117.30	342351189.1
600	$ 92,499,202.00	368749998.6
610	$ 98,679,730.70	395148808.1
620	$ 105,554,703.40	421547617.6
630	$ 113,124,120.10	447946427.1
640	$ 121,387,980.80	474345236.6
650	$ 130,346,285.50	500744046.1
660	$ 139,999,034.20	527142855.6
670	$ 150,346,226.90	553541665.1
680	$ 161,387,863.60	579940474.6
690	$ 173,123,944.30	606339284.1
700	$ 185,554,469.00	632738093.6
710	$ 198,679,437.70	659136903.1
720	$ 212,498,850.40	685535712.6
730	$ 227,012,707.10	711934522.1
740	$ 242,221,007.80	738333331.6
750	$ 258,123,752.50	764732141.1
760	$ 274,720,941.20	791130950.6
770	$ 292,012,573.90	817529760.1
780	$ 310,000,000.00	$ 875,000,000.00
790	$ 328,679,171.30	870327379.1
800	$ 348,054,136.00	896726188.6
810	$ 368,123,544.70	923124998.1
820	$ 388,887,397.40	949523807.6









830	$ 410,345,694.10	975922617.1
840	$ 432,498,434.80	1002321427
850	$ 455,345,619.50	1028720236
860	$ 478,887,248.20	1055119046
870	$ 503,123,320.90	1081517855
880	$ 528,053,837.60	1107916665
890	$ 553,678,798.30	1134315474
900	$ 580,000,000.00	$ 1,240,000,000.00
910		
920		
930		
940		
950		
960		
970		
980		
990		
1000		

540 Case	Estimated Cost Low		Estimated Cost High	
New Gas CT Plant #1	$	60.00	$	100.00
New Gas CT Plant #2	$	-	$	100.00
General Transmission Upgrades				
Energy Storage	$	-	$	-
Additional Two-Shifting of Existing Units				
Total Capital Costs	**$**	**60.00**	**$**	**200.00**
Load Shifting Programs				
Improved Wind Forecasting/yr	$	0.10	$	0.20
Additional Thermal O&M (due to cycling)	$	1.50	$	3.00
Total Variable Costs				
NPV Total	**$**	**60.00**	**$**	**200.00**

785 Case	Estimated Cost Low		Estimated Cost High	
New Gas CC Plant #1	$	70.00	$	100.00
New Gas CC Plant #2	$	70.00	$	100.00
New Gas CC Plant #3	$	-	$	100.00
General Transmission Upgrades & Tieline	$	170.00	$	275.00
Energy Storage	$	-	$	300.00
Additional Two-Shifting of Existing Units				
Total Capital Costs	**$**	**310.00**	**$**	**875.00**
Load Shifting Programs				
Improved Wind Forecasting/yr	$	0.10	$	0.20
Additional Thermal O&M (due to cycling)/yr	$	3.00	$	6.00
Total Variable Costs				
NPV Total	**$**	**310.00**	**$**	**875.00**

900+ Case	Estimated Cost Low		Estimated Cost High	
New Gas CC Plant #1	$	70.00	$	100.00
New Gas CC Plant #2	$	70.00	$	100.00
New Gas CC Plant #3	$	70.00	$	100.00
General Transmission Upgrades & Tieline	$	170.00	$	540.00
Energy Storage (pumped storage)	$	200.00	$	400.00
Additional Two-Shifting of Existing Units				
Total Capital Costs	**$**	**580.00**	**$**	**1,240.00**
Load Shifting Programs				
Improved Wind Forecasting/yr	$	0.10	$	0.20

Additional Thermal O&M (due to cycling)	$	3.00	$	6.00
Total Variable Costs				
NPV Total	**$**	**580.00**	**$**	**1,240.00**

2040
1600
355
254
729
150
3088

ML Base Load

Loads and Resources Outlook for NSPI - Winter 2014/2015 to 2019/2020
(All Values in MW except as noted) No Maritime Link

	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020
Firm Peak Forecast (Base Load)	1,891	1,890	1,892	1,888	1,890	1,889
Planning Reserve Required (20% Firm Peak)	378	378	378	378	378	378
Required Capacity (Firm Peak + Reserve)	2,270	2,268	2,270	2,266	2,268	2,267
Existing Resources	2,340	2,340	2,340	2,340	2,340	2,340
Resource Additions:						
Thermal		-120		-153		
Contracted Wind (Firm capacity)	23					
Biomass		55				
Community Feed-in-Tariff (Firm capacity)	3	3	5	5		
Maritime Link Import						
Total Annual Additions	27	-62	5	-148	0	0
Total Cumulative Additions	27	-35	-30	-178	-178	-178
Total Firm Supply Resources	2,367	2,305	2,310	2,162	2,162	2,162
Surplus/ - Deficit	97	36	40	-104	-106	-105
Reserve Margin %	25%	22%	22%	14%	14%	14%

	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020
	2366.5	2304.8	2309.8	2315.1	2315.1	2315.1
	0.0	0.0	0.0	153.3	153.3	153.3

Thermal		Retire Lin #2 and add BSD#	Retire Lin #1 (-153)
Contracted Wind (Firm capacity)	REA wind (115.8 installed)		
Biomass		MBPP & PHBM (10+45 =55)	
Community Feed-in-Tariff (Firm capacity)			
Maritime Link Import			Maritime Link Firm (153.25 MW)

ML Base Load

Loads and Resources Outlook for NSPI - Winter 2014/2015 to 2019/2020
(All Values in MW except as noted) With Maritime Link

	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020
Firm Peak Forecast (Base Load)	1,891	1,890	1,892	1,888	1,890	1,889
Planning Reserve Required (20% Firm Peak)	378	378	378	378	378	378
Required Capacity (Firm Peak + Reserve)	2,270	2,268	2,270	2,266	2,268	2,267
Existing Resources	2,340	2,340	2,340	2,340	2,340	2,340
Resource Additions:						
Thermal		-120		-153		
Contracted Wind (Firm capacity)	23					
Biomass		55				
Community Feed-in-Tariff (Firm capacity)	3	3	5	5		
Maritime Link Import				153		
Total Annual Additions	27	-62	5	5	0	0
Total Cumulative Additions	27	-35	-30	-25	-25	-25
Total Firm Supply Resources	2,367	2,305	2,310	2,315	2,315	2,315
Surplus/ - Deficit	97	36	40	49	47	48
Reserve Margin %	25%	22%	22%	23%	22%	23%

	2366.5	2304.8	2309.8	2315.1	2315.1	2315.1
	0.0	0.0	0.0	0.1	0.1	0.1
Thermal		Retire Lin #2 and add BSD#		Retire Lin #1 (-153)		
Contracted Wind (Firm capacity)	REA wind (115.8 installed)					
Biomass		MBPP & PHBM (10+45 =55)				
Community Feed-in-Tariff (Firm capacity)						
Maritime Link Import				Maritime Link Firm (153.25 MW)		

ML Base Load

	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Firm Peak Forecast	1,891	1,890	1,892	1,888	1,890	1,889	1,890	1,891	1,895	1,897	1,898	1,901	1,904	1,906	1,911	1,917	1,924	1,930	1,948	1,968	1,987	2,007	2,028	2,048	2,069	2,090
Planning Reserve Required (20% Firm Peak)	378	378	378	378	378	378	378	378	379	379	380	380	381	381	382	383	385	386	390	394	397	401	406	410	414	418
Required Capacity (Firm Peak + Reserve	2,270	2,268	2,270	2,266	2,268	2,267	2,267	2,269	2,274	2,276	2,278	2,281	2,285	2,288	2,293	2,301	2,308	2,315	2,338	2,361	2,385	2,409	2,433	2,458	2,483	2,508
Existing Resources	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340
Resource Additions (MW):																										
Thermal		-120		-153																						
Contracted Wind (Firm capacity)	23.2																									
Biomass		55																								
Community Feed-in-Tariff (Firm capacity)	3.3	3.3	5	5																						
Maritime Link Import				153																						
Assumed Unit Retirement																-153					-153					
Natural Gas Unit																250					250					
Total Annual Additions	26.5	-61.7	5.0	5.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	97.0	0.0	0.0	0.0	0.0	97.0	0.0	0.0	0.0	0.0	0.0
Total Cumulative Additions	26.5	-35.2	-30.2	-25.0	-25.0	-25.0	-25.0	-25.0	-25.0	-25.0	-25.0	-25.0	-25.0	-25.0	-25.0	72.1	72.1	72.1	72.1	72.1	169.1	169.1	169.1	169.1	169.1	169.1
Total Firm Supply Resources	2367	2305	2310	2315	2315	2315	2315	2315	2315	2315	2315	2315	2315	2315	2315	2412	2412	2412	2412	2412	2509	2509	2509	2509	2509	2509
Surplus/ - Deficit	97	36	40	49	47	48	48	46	41	39	37	34	30	27	22	111	104	97	74	51	124	100	76	51	27	1
Reserve Margin %	25%	22%	22%	23%	22%	23%	23%	22%	22%	22%	22%	22%	22%	21%	21%	26%	25%	25%	24%	23%	26%	25%	24%	23%	21%	20%
	2366.5	2304.8	2309.8	2315.1	2315.1	2315.1	2315.1	2315.1	2315.1	2315.1	2315.1	2315.1	2315.1	2315.1	2315.1	2412.1	2412.1	2412.1	2412.1	2412.1	2509.1	2509.1	2509.1	2509.1	2509.1	2509.1
	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0

Thermal		Retire Lin #2 and add I	Retire Lin #1 (-153)
Contracted Wind (Firm capacity)	REA wind (115.8 installed)		
Biomass		MBPP & PHBM (10+45 =55)	
Community Feed-in-Tariff (Firm capacity)			
Maritime Link Import			Maritime Link Firm (153.25 MW)

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Request IR-84:

Regarding Synapse IR-18 Attachment 2:

(a) Please identify the capacity assumed for the each of the CC, CT and pumped-storage plants assumed in the cost estimates for each case.

(b) Please provide the basis for the estimates of high and low capital costs for each plant in each wind power case.

(c) Please provide the basis and derivation of the "General Transmission Upgrades & Time Line" cost estimate for each wind power case.

(d) Please identify the specific transmission facilities included in each case.

Response IR-84:

(a) CTs were assumed at 50 MW and 100 MW. References to CCs in lines 12-14 and 22-24 of the spreadsheet should be to CTs which is only a recognition that the 50 and 100 MW units would not be combined cycle (CC) but simple cycle combustion turbines (CT). There is no change to the economic values modeled. Pumped storage was estimated in the range of 100 to 200 MW capacity.

(b) Referring to Synapse IR-18 Attachment 2, the low capital cost estimates for CTs were for 50 MW units. High capital cost estimates for CTs were for 100 MW units.

(c-d) Please refer to Synapse IR-55 Confidential Attachment 1.

Request IR-85:

Regarding Synapse IR-5:

(a) **Please explain why NSPI cannot provide power-plant output data in its possession in response to discovery.**

(b) **Please provide the data and analysis from which NSPI concluded that "based on the actual wind generation data, the Hatch study underestimated the wind capacity factors for the large wind installations in Pictou/Truro and Valley areas, while it overestimated the capacity factors in the Canso/Cape Breton area," including the actual wind capacity and energy output by month from each of the study areas.**

(c) **The text of the response indicates that each NSPI-owned wind facility is included in Attachment 1, but Attachment 1 lists only Nuttby and Gulliver Cove.**

(i) **Please provide data for each of the other NSPI-owned farms, Digby and Point Tupper.**

(ii) **If the Gulliver Cove wind plant is the Digby plant, please so state. Otherwise, please describe the Gulliver Cove wind plant.**

Response IR-85:

(a) Hourly generation data associated with Independent Power Producers (IPP) is third party data with commercial value, which is provided to NS Power for operational use, but is not owned by NS Power. Hourly wind generation associated with IPPs can be requested from IPPs who own the data. NS Power provided amalgamated hourly generation of all IPPs.

(b) Please refer to Nova Scotia Wind Integration study by HATCH Ltd, table 4-2.

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

Please also refer to SBA IR-67 and Can WEA IR-1 for the data required to calculate actual IPP generator capacity factors.

(c) NS Power has full ownership in Gulliver Cove and Nuttby wind farms. NS Power is a minority owner of Point Tupper wind farm and as such Point Tupper wind farm is considered to be an IPP. Gulliver Cove is the Digby or Digby Neck wind farm.

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Request IR-86:

Reference response to Synapse IR-7:

(a) Please describe the "system security" problem that caused each curtailment. Specifically, was the problem related to overloading of a specific line, minimum generation levels, or some other concern?

(b) Please provide the duration of each curtailment listed.

(c) Please provide the operational level of each wind plant prior to the curtailment.

(d) Please provide the extent of each "partial" curtailment.

(i) Were the required curtailments stated as a fixed cap on the wind farm output, a required percentage reduction, or something else?

Response IR-86:

(a) NS Power believes the question refers to Synapse IR-8. All wind curtailment events were due to reaching minimum safe generation levels, except for two Glen Dhu curtailments: 2012-08-31 00:33 and 2012-09-01 05:45, which were due to transmission system constraints.

(b)

DATE	Wind Farms	Level of Curtailment	Restored
2011-10-26 02:06	Bear Head	To 0 %	5:34
	Nuttby	To 0%	5:34

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DATE	Wind Farms	Level of Curtailment	Restored
2011-12-08 05:45	Gulliver's Cove	To 33%	6:10
	Dalhousie	To 66%	6:04
2012-07-20 03:42	Glen Dhu	To 66%	2:25
	Lingan	To 33%	2:28
	Pubnico Point	To 66%	2:32
	Maryvale	To 0%	2:37
	Amherst	To 33%	2:40
2012-08-28 03:39	Gulliver's Cove	To 66%	3:00
	Dalhousie	To 66%	3:02
2012-08-31 00:33	Glen Dhu	To 33%	n/a.
2012-09-01 05:45	Glen Dhu	To 33%	9:48 – 10:07
2012-10-16 01:25	Nuttby	To 50%	3:48
2012-10-16 01:28	Bear Head	To 66%	3:48
2012-10-16 01:34	Glen Dhu	To 33%	3:48
2012-12-11 01:47	Lingan	To 66%	4:41
2012-12-11 01:50	Pubnico	To 66%	4:41
2012-12-11 01:54	Maryvale	To 0%	4:43
2012-12-11 01:55	Amherst	To 0 %	4:44
2012-12-11 01:57	Gulliver's Cove	To 66%	4:44
2012-12-11 02:04	Dalhousie	To 66%	4:45
2012-12-11 02:07	Nuttby	To 50%	4:46
2012-12-11 02:25	Bear Head	To 33%	4:47

(c) Hourly wind generation data is provided in Synapse IR-5 and the explanation in CA IR-85. Hourly IPP generation data is third party confidential. Please see CA IR-85.

(d) Please refer to part (b).

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Request IR-87:

Reference response to CA IR-26 and Appendix 6.02, p. 14:

(a) Since the curtailments listed in response to Synapse IR-7 include several farms that are not included in the list of ERIS facilities, please explain how these curtailments are relevant to ERIS service.

(b) Since the curtailments appear to have all been at low-load periods, between midnight and 6 am, how do these curtailments support the claim that "When the system is congested because of load, a generator with ERIS can be curtailed to allow the transmission system to operate within acceptable transfer limits and hence provides little in terms of capacity contribution to the system's reserve requirements."

(c) Does NSPI agree that it has never curtailed a wind farm at high-load hours?

Response IR-87:

(a) Wind generation curtailment or the redispatch of any form of generation can and will be undertaken by the system operator to support system reliability. Wind generation curtailment at low load would be the system operator's response to excess energy on the power system and would be implemented after other redispatch measures are taken. All generating facilities, regardless of the form of interconnection service, are subject to system operator direction to support the reliability needs of the power system.

(b) It is correct that the majority of wind generation curtailments will happen at low load periods. The accounting of firm generating capacity for the purpose of planning reserve margin determination is a different consideration. Projects seeking ERIS transmission interconnection forego the transmission upgrades necessary to guarantee the availability of transmission capacity to allow their full available production at all times. Under most circumstances within NS Power's market operations, the conventional generation will back down to allow the renewable asset to operate. This enables the renewable electricity to be produced for RES compliance and achieves the displacement of fossil fired generation contemplated by the environmental legislation. However, at peak system load, the circumstances used in capacity planning, the full capacity of the firm generating assets and the capacity of the ERIS resource cannot both be counted as the transmission constraints will impose a cap on the sum of the two. Any capacity associated with the ERIS project (wind generation or otherwise) is not counted toward the firm system capacity.

(c) Yes, with the present level of wind on the system NS Power has not had to curtail a wind farm at high loads.

Request IR-88:

Reference Response to CA IR-32:

(a) How is the fact "that the Atlantic region is winter peaking" relevant to the issue of transmission through New Brunswick to New England?

(b) Please provide any evidence that since "the return of the largest generator on the system, Pt Lepreau," the Atlantic region has been "minimum load constrained."

(c) Please provide any available data on the number of low-load hours when the transmission from New Brunswick to New England has operated at maximum capacity, since the return of Pt. Lepreau.

(d) Please provide the "preliminary stability simulations" that indicate that the second transmission line would be required at or near 500 MW of wind in Nova Scotia.

Response IR-88:

(a) The fact that the Atlantic region is winter-peaking and New England is summer-peaking means that transmission interconnection from New Brunswick to New England is more likely to be scheduled at limits in summer than in winter. Conversely, in winter, capacity in the Atlantic region is more likely to be used to serve domestic load than export to New England.

(b) Point Lepreau is a nuclear unit. It is a feature of nuclear generation technology that such units are operated at "base load" levels and do not cycle on a daily basis. Therefore it would be expected that the aggregate generation fleet in the Atlantic region with Point Lepreau on-line would have less down-turn capability in times of light load than otherwise would be the case without a large nuclear unit on-line.

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(c) Point Lepreau returned to commercial service on 2012-11-23 hence there has not been a period of summer low load since Point Lepreau generation came back on-line. Reference NB Power Press Release: http://www.nbpower.com/html/en/about/media/media_release/pdfs/ENPLSGNovember232012.pdf

(d) Please refer to CA IR-30.

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Request IR-89:

Reference Response to CA IR-33:

Please describe the "out-of-merit redispatch of thermal generation in Cape Breton" that has been used to "handle" "ERIS issues for wind projects east of Onslow."

(a) If this redispatch consists of turning down thermal generation if wind generation is available, please explain what is "out-of-merit" about the dispatch.

Response IR-89:

Energy Resource Interconnection Service (ERIS) is defined in Section 3.2.1 of the NS Power Standard Generator Interconnection Procedures [1]as:

> *"ER Interconnection Service allows Interconnection Customer to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an 'as available' basis."*

The System Impact Study conducted for the Interconnection Customer seeking ERIS identifies the transmission upgrades necessary to permit the proposed generation facility to operate at full output and identify the maximum output, *at the time the study is performed*, without requiring additional Network Upgrades.

The SIS conducted for the ERIS wind generation projects east of Onslow determined that the transmission interfaces Cape Breton Export and Onslow Import would exceed reliability limits if these projects displaced generation west of Onslow (e.g. gas-fired thermal generation in Halifax), but would remain within limits if the proposed wind generation displaced thermal generation east

[1] The NS Power Standard Generator Interconnection Procedures can be accessed at http://oasis.nspower.ca/site-nsp/media/Oasis/RevisedGIPFeb102010.pdf

of Onslow, coal-fired generation in Cape Breton or Trenton. At the time these studies were performed (2007-2008) the historical marginal cost of coal was lower than natural gas. Therefore assuming that the new wind generation displaces cheaper coal-fired generation in Cape Breton, rather than more expensive natural gas fired generation in Halifax, allowed NS Power to "handle" these ERIS projects without Network Upgrades.

(a) Not all the thermal generation can be turned down to provide the transmission congestion relief east of Onlow. Only thermal generation east of Onslow provides such relief. As stated above, thermal generation east of Onslow is coal-fired. Thermal generation west of Onslow is fired by oil or natural gas. When coal-fired generation is cheaper than gas/oil fired generation, turning down that coal-fired generation constitutes an "out of merit" dispatch.

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Request IR-90:

Please clarify whether NSPML believes that the Supplemental Energy fully compensates Nova Scotia ratepayers for the transfer of facilities with a 50-year life at the end of 35-year contract (Application, p. 79).

(a) If so, please provide the basis for that belief.

Response IR-90:

Yes. The calculation of Supplemental Energy was part of the negotiation of the full Maritime Link Project as outlined in the Application and fully represents the value of the adjustment of amortization from 50 to 35 years as outlined in the Application on page 79, lines 15 - 23. NSPML believes that this Project as a whole is the lowest long-term cost alternative available to Nova Scotia customers.

Request IR-91:

Reference CA IR-44:

(a) Please identify the hours in 2012 in which "NSPI has to start expensive diesel combustion turbines" to provide down-regulation.

(b) Please explain why NSPI backed the steam plants to minimum and started the combustion turbines, rather than running the steam plant at slightly above minimum to provide down-regulation.

Response IR-91:

(a-b) Upon further investigation it was determined that dispatch described in the referenced IR response was the result of circumstances other than those cited. CT dispatch was not to provide down-regulation. We apologize for this error.

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Request IR-92:

Reference CA IR-44:

Please identify the dates of the "Min to max swings of over 700 MW [that occur] on the NS Power system today."

Response IR-92:

The following table provides the occurrence of 700 MW swings in load net of wind over the past two years. NS Power expects the occurrence of these events to increase as more wind generation is added to the power system.

Start Date	Start Hour	End Date	End Hour	Start Load (MW)	End Load (MW)	Load Change (MW)
1/18/2011	7:00-8:00 AM	1/19/2011	3:00-4:00 AM	1944	1241	-703
2/26/2011	2:00-3:00 AM	2/26/2011	6:00-7:00 PM	1102	1806	704
2/28/2011	7:00-8:00 AM	3/1/2011	2:00-3:00 AM	1903	1161	-742
11/21/2011	3:00-4:00 AM	11/21/2011	5:00-6:00 PM	690	1497	807
11/27/2011	5:00-6:00 PM	11/28/2011	4:00-5:00 AM	1494	791	-703
12/7/2011	5:00-6:00 PM	12/8/2011	4:00-5:00 AM	1534	753	-781
12/11/2011	2:00-3:00 AM	12/11/2011	5:00-6:00 PM	889	1616	727
12/14/2011	2:00-3:00 AM	12/14/2011	5:00-6:00 PM	922	1694	772
12/15/2011	8:00-9:00 AM	12/16/2011	4:00-5:00 AM	1513	765	-748
12/21/2011	8:00-9:00 AM	12/22/2011	3:00-4:00 AM	1548	838	-710
1/11/2012	4:00-5:00 AM	1/11/2012	5:00-6:00 PM	910	1613	703
1/12/2012	8:00-9:00 AM	1/13/2012	3:00-4:00 AM	1687	913	-774
1/17/2012	5:00-6:00 PM	1/18/2012	3:00-4:00 AM	1642	869	-773
1/23/2012	8:00-9:00 AM	1/24/2012	4:00-5:00 AM	1799	925	-874
10/19/2012	8:00-9:00 AM	10/20/2012	4:00-5:00 AM	1345	633	-712
12/4/2012	5:00-6:00 PM	12/5/2012	4:00-5:00 AM	1525	742	-783
12/10/2012	8:00-9:00 AM	12/11/2012	1:00-2:00 AM	1577	795	-782
12/11/2012	1:00-2:00 AM	12/11/2012	5:00-6:00 PM	795	1584	789

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Request IR-93:

Reference CA IR-49:

(a) Please provide the GWh and MW contributed to the "base" load forecast each year by the higher residential heating saturation.

(b) Please provide the GWh and MW contributed each year to the "base" load forecast each year by the EV assumption.

Response IR-93:

(a-b) The data is shown in the table below.

	Additional Heating (cumulative)		Electric Vehicle (cumulative)	
Year	GWh	MW	GWh	MW
2015	38	9	2	0
2016	56	13	3	1
2017	75	17	4	1
2018	94	22	6	1
2019	114	26	7	2
2020	134	31	10	2
2021	154	35	12	3
2022	175	40	15	3
2023	195	45	18	4
2024	216	50	20	5
2025	237	54	23	5
2026	259	59	26	6
2027	280	64	29	7
2028	302	69	32	7
2029	324	74	35	8
2030	346	79	38	9
2031	368	84	41	9
2032	391	89	45	10

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	Additional Heating (cumulative)		Electric Vehicle (cumulative)	
Year	**GWh**	**MW**	**GWh**	**MW**
2033	413	94	48	11
2034	435	99	51	12
2035	457	104	55	12
2036	479	109	58	13
2037	502	114	62	14
2038	524	119	65	15
2039	546	124	69	16
2040	568	129	73	17

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Request IR-94:

Reference CA IR-51:

(a) Please provide any available analysis of the effect on the economics of the Maritime Link of removing the PH load from the low load forecast.

(b) Please provide any available analysis of the effect on the economics of the Maritime Link of removing the PH load from the high load forecast.

(c) The referenced NSUARB IR-78 does not respond to parts (b) and (c) of CA IR-51. Please respond to those questions.

Response IR-94:

(a-c) As stated in NSUARB IR-78(c) and in accordance with the Load Retention Tariff, "PH load is not factored into capacity planning." NSPML accepts the characterization that the Alternatives Analysis filed in support of the Application is "planning work"; but the Alternatives Analysis is not "capacity planning work". The Analysis contains NSPML's available analysis relating to industrial load, and removes a generic industrial load equivalent to the Port Hawkesbury facility from the low load forecast in 2019. The difference between the High Load Scenario and the Low Load Scenario is greater than the equivalent industrial load of the Port Hawkesbury facility.

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Request IR-95:

Reference NSPI's 2013 ACE filing, pp. 27–28, and CA IR-69:

(a) Please identify where the Maritime Link application, especially Appendix 6.07, includes the costs of each of the transmission projects listed as being related to the Maritime Link:

(i) 43677 Woodbine Substation Expansion
(ii) 43324 L6513 Rebuild/upgrade line terminals
(iii) 43678 Strait Crossing: Separate L-8004/L-7005
(iv) 43679 L-7015 ROW Modifications.

(b) Please explain what entity would own each of these projects: NSPI for NSPML.

(c) Please explain why the project is necessary to support the Maritime Link.

Response IR-95:

(a) Please refer to NSUARB IR-32 (c). Of the costs listed, only the Woodbine Substation costs were included in the Maritime Link Project application. The remaining transmission projects were identified in the project Application but will be submitted separately by NS Power. These costs are expected to be offset by revenues collected through the transmission tariff.

(b-c) Please refer to CA/SBA IR-93 and NSUARB IR-32 (c). NSPML will own the Woodbine Substation Expansion during the term, at which time that asset would be transferred to NS Power. NS Power would own the other projects listed.

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Request IR-96:

Reference CA IR-70:

Please identify where the Maritime Link application, especially Appendix 6.07, includes the costs of each of the new 345kV interconnection with New Brunswick.

Response IR-96:

The Other Import alternative includes a new 345 kV interconnection with New Brunswick. Please refer to CA/SBA IR-283 and Appendix 6.05 of the Application.

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Request IR-97:

Reference CA IR-71:

Please explain the answers of “no” to parts (a) and (d), considering that NS Power must pay Nalcor its full avoided cost for the energy delivered under these circumstances.

Response IR-97:

The “no” responses to CA IR-71 (a) & (d) are reflective of Nalcor’s contractual rights not providing an option to unilaterally put their energy to NS Power. Certain conditions need to exist before the energy is directed to Nova Scotia, including (1) Nalcor would need to otherwise be able to place a valid transaction into New England, (2) transmission is not available through New Brunswick pursuant to the NBTUA, (3) no Force Majeure is applicable, and (4) there are no system reliability constraints in Nova Scotia. The cost for that energy to NS Power will never be higher than NS Power’s avoided cost.

NON-CONFIDENTIAL

Request IR-98:

Reference CA IR-77 Attachment 1:

The request was for the workpapers supporting the estimate. The attachment consists only of conclusory results.

(a) Please explain how NSPML selected the post-2025 expansion plans for the ML and Higher Imports cases.

(b) Please provide the derivation of page 2 of Attachment 1, including the amount of energy purchased, the price of the purchases, the avoided fuel and operating costs, and transmission and generation capital costs.

Response IR-98:

(a) The resource plans for the Maritime Link Base Load case and the case with Higher Imports were developed from Strategist resource optimizations. The model is offered different options to select from and solves for the lowest long term cost taking into condsideration costs, environmental emission factors, planning reserve, energy and capacity requirements, and renewable requirements. The model determines the timing and types of resource to add in the plan to meet these constraints. Please refer to CA/SBA IR-351 (b) for further details about the model.

(b) Please refer to CA/SBA IR-331 parts (b) and (c) for the Strategist input and output reports. The annual planning period values shown on page 2 of Attachment 1 for the Maritime Link Base Load and the Higher Imports case are taken from the Strategist model. Strategist takes the input data, executes the run and produces the output results. There are no intermediate materials used to obtain these values.