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Request IR-1:

Please provide the expected retirement date for each of NSPI's owned generating assets.

Response IR-1:

Please refer to NSUARB IR-44.

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Request IR-2:

Please provide a summary of NSPI's current expectation of when the Maritime Link will be placed into service and provide imported generation.

Response IR-2:

The Maritime Link is on schedule to be placed in service in Q4 of 2017.

Request IR-3:

Please reference page 88 of Exhibit N-1, which shows that NSPI's current projections for 2016 sustaining capital expenditure are about $20 million more than predicted in the IRP, an increase of roughly 40%.

(a) If actual capital costs continue to be about 40% higher than estimated in the IRP for the next ten years, how, if at all, would this change NSPI's generation retirement and investment strategy?

(b) Please provide a similar comparison for 2015 capital spending and please include a table that provides the dollars for each category shown in the bar chart.

Response IR-3:

(a) The IRP evaluated three retirement scenarios under different Candidate Resource Plans. Candidate Resource Planning investigated different outcomes for comparison purposes, but did not seek to determine a fully optimized plan. The IRP did not contain a sensitivity analysis for changes to sustaining capital investment. However, as discussed on Page 88 of the 2016 ACE Plan, the increase in capital investment in the 2016 ACE is largely timing differences from the assumptions in the long-term levelized sustaining capital forecast used in the IRP. The investments responsible for the difference in the ACE Plan and the long term levelized assumption of the IRP are related to assets like ash sites and combustion turbines that would be required under all Candidate Resource Plans. As the IRP was a comparative exercise, an increase as proposed would not be expected to drive significant changes in relative resource plan outcomes.

(b) Please refer to Attachment 1.

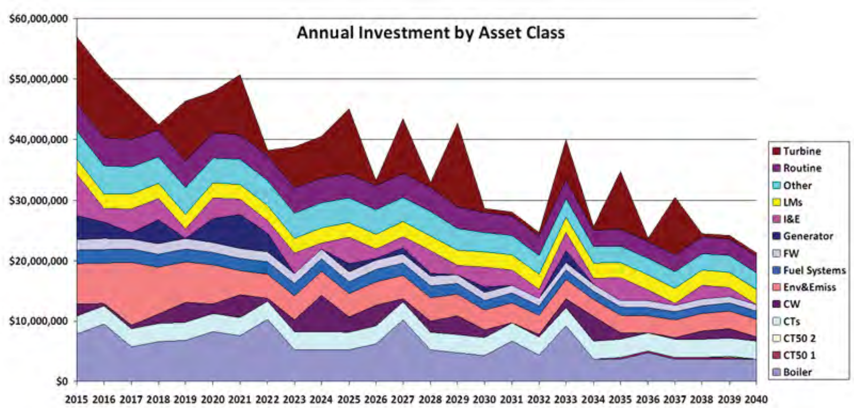
REDACTED (CONFIDENTIAL INFORMATION REMOVED)

ACE 2015 – Alignment with IRP

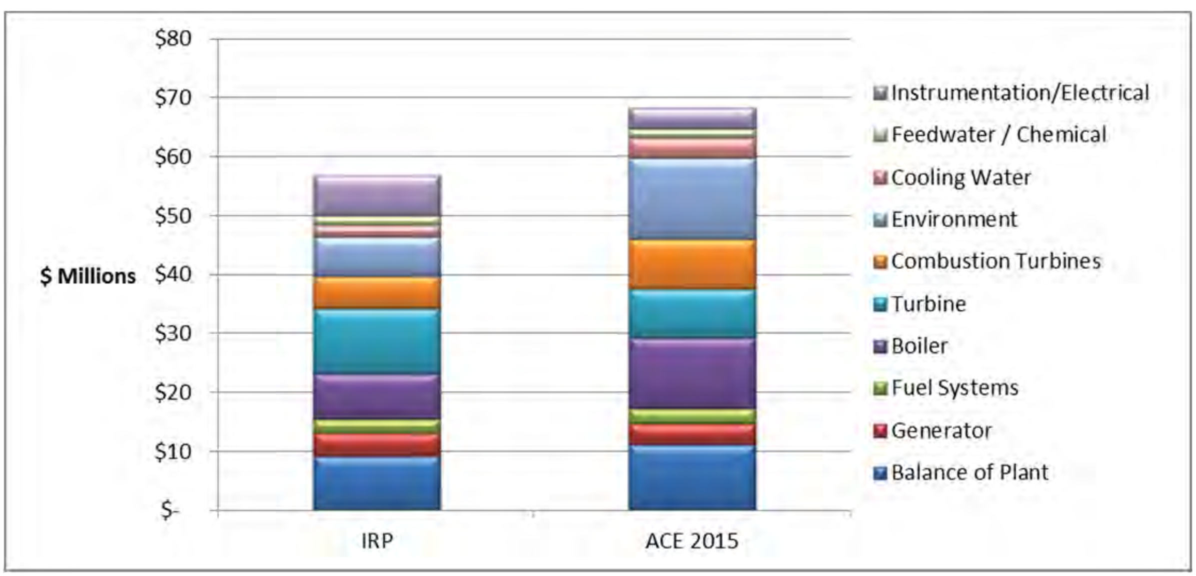
Sustaining capital in NS Power's thermal and combustion turbine fleet is well aligned with the assumptions used throughout the 2014 Integrated Resource Plan. The capital investment included in ACE 2015 would not be expected to change no matter what resource plan is used from the 2014 IRP process.

An important consideration when comparing a singular capital year from an ACE Plan to a long term planning exercise such as the IRP is the levelling of investment done in the formation of a 25 year capital forecast used within the IRP. Outside of major asset classes (turbines, generators, etc), the investment in asset classes are levelized throughout the expected life of the associated unit.

2014 IRP Capital Forecast



2015 ACE Plan vs IRP Forecast



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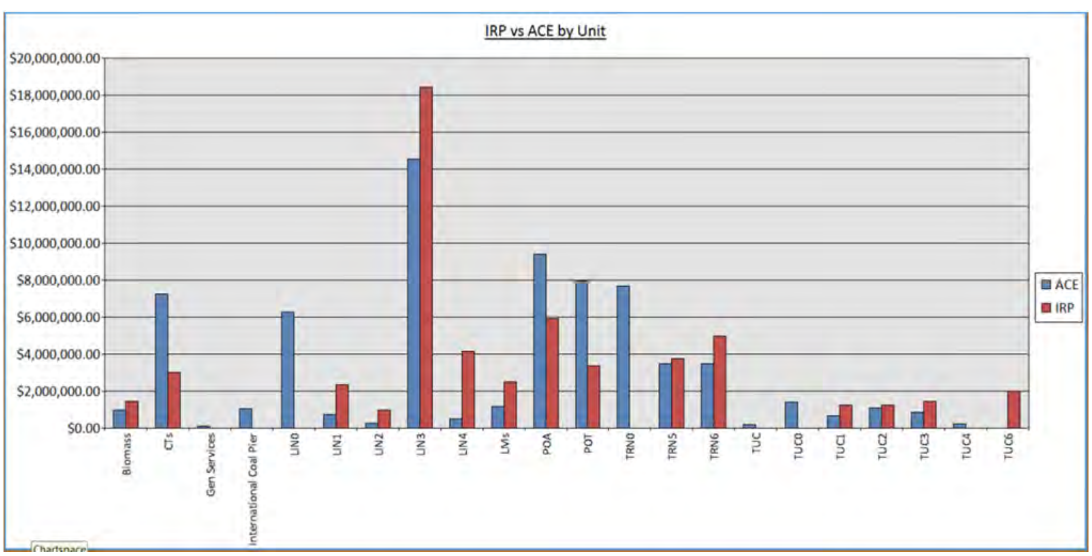
The following table includes the actual dollar figures used in the table above.

Asset Class	IRP	ACE 2015
Balance of Plant	$9,250,000	$11,246,083
Generator	$3,950,000	$3,463,321
Fuel Systems	$2,233,750	$2,641,308
Boiler	$7,808,750	$11,956,707
Turbine	$10,925,000	$8,361,230
Combustion Turbines	$5,500,000	$8,423,251
Environment	$6,725,000	$13,700,542
Cooling Water	$1,962,500	$3,464,096
Feedwater / Chemical	$1,750,000	$1,469,851
Instrumentation/Electrical	$6,800,000	$3,619,540

While ACE 2015 is higher than the IRP forecast, the variance is largely due to two items. First being investment in ash sites. As mentioned above, Ash Site investment was levelized throughout the planning period of the IRP however can be expected to have a varying amount of investment year over year. In addition to this, Ash site investment should be looked at as a sunk cost. The majority of this investment is required, and driven by regulatory requirements, even if the associated thermal plant were to be retired today. The second primary driver is investment in our Combustion Turbine fleet. Investment, originally anticipated to occur in future years, was completed in 2015. This increased investment does not have an effect on alignment with the IRP as all Combustion Turbines are anticipated to operate throughout the IRP Planning Period.

In addition to the above, the investment in the units that are anticipated to be retired within the planning period has remained consistent with IRP values. Increases from the IRP capital forecast have primarily occurred on the thermal units that will be operational throughout the Planning Period as the chart below shows.



Request IR-4:

Please reference pages 111-112 of Exhibit N-1, which lists 2016 capital projects that directly impact deteriorated equipment failures. What is the expected reduction in customer hours of interruption from all of these projects?

Response IR-4:

The table below references the 2016 capital projects outlined on pages 111-112 of Exhibit N-1, with a summary of their expected outcomes. Rather than an overall reduction in customer hours of interruption, the routines and special projects listed below are primarily expected to result in sustained reliability performance and prevention of increased occurrence of outages.

Project	Description
Routine Programs D005 and D055	These routines are for maintaining performance and replacing like-for-like assets. D005 is utilized to replace or upgrade failed distribution equipment. D055 is utilized for proactive replacement of distribution equipment at risk of failure, based on inspections and engineering analysis.
CI 47766 70V-312G	This project improves reliability and reduces exposure for 192 customers by replacing primary conductor that has a high quantity of splices. Outages for planned maintenance for this section have occurred in the past, totaling 400 Customer Hours of Interruption.
CI 47756 36V-303	There have been recent outages impacting 170 customers due to conductor failures, totaling 750 Customer Hours of Interruption.
CI 47752 4S-333	This feeder rebuild and reconfiguration will reduce outage risk for 1,020 customers due to deteriorated equipment outages, and will also improve response time by improving accessibility to sections of the line.

Project	Description
CI 45031 and 47773 3N	This multi-phase conversion program upgrades pole-top transformers and addresses overload issues, reducing exposure for 1,730 customers. Deteriorated poles and pole-top transformers will be replaced as part of the conversion.
CI 47765 58C-405 and 11C	Replacing and reconfiguring this feeder allows for the removal of the deteriorated 11C Substation, which reduces outage exposure for 1,510 customers, including improved accessibility to the line and replacement of deteriorated poles.
CI 47774 546C-311	Replacing the step-down transformers and rebuilding the surrounding distribution plant to roadside will reduce the risk of an outage and reduces response time for 690 customers.
CI 46456 11W	The existing 4kV system in downtown Yarmouth is deteriorated and is islanded, with no ability to be supplied from the surrounding feeders (which are all 12kV) should the end-of-life 11W transformer fail. Converting the 11W feeders and transferring their load removes the risk of an extended outage to over 640 customers in the event of the 11W transformer failure, and also increases the opportunity for switching during outages.
CI 47760 85S-402	Failed insulators and failed tie wire events have resulted in over 2,500 customer interruptions and over 9,000 customer hours of interruption over the last five years.
CI 47734 1C-411	Upgrading the conductor on the targeted section of line reduces exposure of conductor failures to 760 customers. In addition, the conductor upgrade permits this feeder to carry additional load from adjacent feeders through feeder ties in the event of outages, which improves restoration time for an additional 400 customers.
CI 47754 63V-313G	This reconductor and reinsulate project reduces outage risk for 1,260 customers. Two conductor failures have occurred in the two previous years, resulting in 500 Customer Hours of Interruption.

Project	Description
CI 43177 103W-311	The third phase of this project continues to upgrade primary conductor, reducing outage risk for 1,090 customers, and also improves accessibility to targeted sections of the line.
CI 47777 70W-321G	This project reduces outage exposure for 570 customers by bringing deteriorated plant to road side.
CI 47753 24C-442GB	This distribution line rebuild reduces the risk of conductor failure outages to 2,400 customers. In addition, bringing the line to roadside reduces restoration times by improving accessibility to the line. Recent outages have accounted for 2,600 Customer Hours of Interruption. The upgraded line will also act as an alternate supply for the Town of Canso.
CI 45003 Hydraulic Reclosers	This project replaces 7 deteriorated hydraulic reclosers on the distribution system. Approximately 9,000 Customer Hours of Interruption due to recloser failure will be avoided.
CI 41383 1H-419 and 1H-431	30% of this multi-year project is remaining for 2016. Replacing end-of-life, underground, 25kV cables and accessories will reduce extended outage risk due to cable failure for 600 downtown Halifax customers including the Maritime Center, Ralston Building, Summit Place, Radisson Hotel, Public Works Canada, Bank of NS and many large residential buildings.
CI 47787 2H	This project installs 4 new feeders at the 2H Armdale substation to address the load growth on the Halifax peninsula, St Margaret's Bay and the Herring Cove Road areas. They will provide additional capacity to all of these areas, and provide new capabilities to transfer load between existing 2H feeders, 103H feeders and 104H feeders for partial restoration of customers in the event of outages.

Request IR-5:

In addition to the transmission and distribution right of way widening routines, please identify any 2016 capital projects that are related to improving storm performance due to information gathered regarding the system outages from Post Tropical Storm Arthur.

Response IR-5:

2016 capital projects are selected based on review of reliability data, inspection results, asset management strategies and engineering analysis. Investments related directly to information gathered during Post Tropical Storm Arthur are T010, D010 and CI 48254 IT Outage Communication System and Enhanced Disaster Recovery.

Request IR-6:

Please refer to the chart on page 119 of Exhibit N-1, which shows changes in substation transformer age profiles:

(a) Why aren't the oldest transformers, those age 65+ years, being targeted for replacement in 2016?

(b) When does NSPI plan to replace the oldest transformers?

Response IR-6:

(a-b) Age is one parameter utilized to calculate the risk score for the transformer. Other parameters that are also utilized are:

- Design
- Manufacturing
- Loading
- Maintenance Results
- Operating Environment
- System Impact
- Reliability

NS Power has not experienced recent reliability impacts due to its older transformers and they continue to operate within acceptable limits. Transformers installed during the 1950s and 1960s were generally designed and constructed with conservative margins for thermal and electrical stress leading to more robust equipment compared to the tighter specifications of modern designs. As with other transformers, periodic inspection and testing as well as preventative maintenance programs are designed to identify issues and mitigate risks on older units prior to failure. As a result, capital replacements do not necessarily focus solely on the oldest transformers. Other parameters are included in the replacement risk analysis.

Request IR-7:

Please refer to the chart on page 122 of Exhibit N-1, which shows current transmission conductor age profiles. NSPI states that 14% of its conductor is beyond 55 years of service, but the chart shows a very low amount of conductor under 20 years of service. Why hasn't there been more replacement of transmission conductor in the past 20 years?

Response IR-7:

As with other transmission and distribution asset classes, the age of a conductor is just one of a number of contributing factors used to determine if a given line segment requires replacement. NS Power has experienced few instances of transmission conductor failure that can be attributed solely to advanced age. As a result of the continued performance of conductor approaching 55 years of age and beyond, NS Power believes that relying on age alone to drive replacement programs would lead to premature capital investment that ultimately does not contribute to improved overall transmission reliability. Consequently, increased replacement of transmission conductor during the past 20 years was not recommended. To improve targeting of effective transmission conductor replacement, NS Power is investigating complementary assessment tools to evaluate the condition of transmission conductor currently in service.

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Request IR-8:

Please provide a list of all projects where NSPI has performed an economic analysis using its EAM, for which the expected payback of the project is greater than five years. For each of the listed projects, has NSPI performed any sensitivity analysis of its assumed post five-year escalation rate? If so, what were the results? If not, why not?

Response IR-8:

The following projects had an economic analysis performed that indicated a payback period of greater than 5 years:

- CI 47172 HYD Tidewater Overhaul
- CI 47332 HYD Methals Overhaul
- CI 47658 LIN4 L-0 Blade Replacement
- CI 47673 LIN4 Rotor Rewind
- CI 47869 LIN4 Bottom Ash Refurbishment

NS Power did not perform any sensitivity analysis of the assumed post five-year escalation rate. As an example, for CI 47658 LIN4 L-0 Blade Replacement, if the replacement energy costs decreased by the 2% they are currently escalated at starting in 2021, the payback period of the project goes from a 7.3 year to 7.5 year payback period. NS Power is confident that it would require a large decrease in replacement energy costs for these projects to be deemed uneconomic.

Request IR-9:

Please reference Exhibit N-1.4, the electronic Revenue Requirement calculation submitted with the 2016 ACE Plan:

(a) What are the numbers labeled as 'Change in Incremental Revenue Requirement from Previous Year' supposed to represent? Do they represent an estimated year-over-year change in revenue requirement?

(b) The incremental spend is calculated net of depreciation of all assets. Why is depreciation subtracted again to calculate the average plant balance for purposes of calculating cost of capital?

(c) Calculation of incremental average rate base for purposes of estimating finance expense appears to be inconsistent in the table. In the first year, the initial balance is zero. In other years its incremental capital from the previous year. In order to calculate the change in revenue requirement from 2015, why isn't the 2016 starting balance equal to the previous year's incremental capital spend?

(d) Why is depreciation expense multiplied by the fraction of incremental spend as a portion of total spend when depreciation is a function of depreciation rate and additions less retirements and not capital spend net of depreciation of all assets?

(e) Does NSPI assume that total Administrative Overhead, whether expensed or capitalized, depends on total capital expenditure? Why or why not?

(f) Why is the administrative overhead credit multiplied by the fraction of incremental spend as a portion of total spend when year-over-year change in the amount of capitalized administrative overhead is a function of the change in total capital spend year-over-year and not the change in capital spend net of depreciation of all assets?

(g) Calculation of the administrative overhead appears to be inconsistent in the table. In the first year, the $12.6 million decrease to revenue requirement includes the entire $11 million administrative overhead credit. In subsequent years, the difference in administrative overhead credit impacts the change in incremental revenue requirement. For instance, the $0.6 million increase in revenue requirement in 2017 reflects the $6.5 million increase in administrative overhead credit in that year. In order to calculate the change in revenue requirement from 2015, why isn't the change in administrative overhead credit from 2015 incorporated into the calculation?

(h) AFUDC represents a financing cost that is only incurred to support capital expenditure. How is the incremental cost of AFUDC incorporated into the revenue requirement calculation? Why is AFUDC shown as a credit to revenue requirement?

Response IR-9:

(a) The numbers labeled as 'Change in Incremental Revenue Requirement from Previous Year' represent an estimated year-over-year change in revenue requirement as a result of the impact of the five-year capital plan. The line item labeled 'Incremental Revenue Requirement of five-year capital plan' is the estimated revenue requirement effect of the five year capital plan in that year. The line titled 'Change in Incremental Revenue Requirement from Previous Year' is calculated as the current year's incremental revenue requirement of the five-year capital plan less the previous year's incremental revenue requirement of the five-year capital plan.

(b) In order to determine the average plant balance for purposes of calculating the cost of capital, only the impacts of the five-year capital plan are considered. Only the forecasted incremental depreciation related to assets added from 2015-2020 would be deducted from the capital spend for this purpose. The incremental depreciation deducted from capital spending to determine the average plant value is the same as that included in the expenses portion of the tables used to calculate revenue requirement.

The incremental spend as a portion of total spend is calculated by deducting the forecasted depreciation expense of all NS Power's assets, including those added in previous years, from the forecasted capital expenditures to determine the portion of expenditures that should be considered growth above the existing asset base. The depreciation expense related to all assets is only used to calculate the incremental spend as a portion of total spend, depreciation expense of all assets is not included in the expenses section used to calculate the revenue requirement.

(c) The intent of these tables is to determine the revenue requirement impact of the forecasted five-year capital plan. At the start of 2016, there would be a $0 forecasted beginning balance of capital assets related to the five-year forecast. If the beginning balance was the previous year's ending balance of incremental regulated capital assets, financing costs related to capital assets that are not included in the five-year capital plan would be considered in the calculation of revenue requirement.

(d) Depreciation expense is calculated by multiplying depreciation rates by the forecasted balance of assets in service related to the five-year plan. This calculated depreciation expense is then multiplied by the incremental spend as a portion of total spend as that is the portion of depreciation that would be attributed to the growth in rate base or is above sustaining investment in NS Power's capital assets. The assumption is that if investment is at the same level as depreciation, there will be no net increase in expenses or savings for customers as NS Power is simply maintaining its current asset base. This is a conservative assumption as most of the assets that are being replaced would be 20 years or older and replacement assets would cost more due to inflation. If the incremental spend as a portion of total spend was not applied to total depreciation expense, the effect of decreased depreciation related to the retirement of previously installed assets would not be considered, overstating the incremental revenue requirement impact calculated in these tables.

(e) NS Power assumes that the support costs required to execute its capital program do not vary when the capital program stays within the normal range for the Company. The portion of these support costs that would be capitalized as administrative overhead (AO) vs. expensed as Operating, Maintenance and General (OM&G) costs would vary depending upon the ratio of capital and operating work that is undertaken in the year.

NS Power assumes that the support costs remain constant as staffing and other OM&G costs do not vary significantly as a result of a year-to-year variance in the expected capital spending. If there were a large increase in capital spending in a given year, NS Power may contract an increased amount of this work out to external vendors or hire additional term employees. All of these costs would be directly charged to the capital projects they were associated with and would not be included in the support costs that are allocated between AO and OM&G.

If there was a year with a significantly lower capital spend, the assumption is that NS Power's support costs would not vary significantly provided spend was expected to return to the normal range in the following year. The reduction in capital spend would result in less work contracted to external vendors and a lower number of term employees, these decreased charges would be related to direct capital costs and not the support costs used to calculate AO.

(f) AO is calculated by multiplying the forecasted total capital spend by the forecasted ratio of AO to total capital spend. This calculated AO is then multiplied by the incremental spend as a portion of total spend as that is the portion of depreciation that would be attributed to the growth in rate base or is above sustaining investment in NS Power's capital assets. Similar to depreciation expense, AFUDC and capital cost allowance, only the portion of AO related to the spending in excess of that which maintains the asset base is included in the calculation of incremental revenue requirement. Including the entire amount of the AO credit would understate the incremental revenue requirement impact of the five-year capital plan.

(g) The AO credit is treated consistently in the calculation of the 'Incremental Revenue Requirement of five-year capital plan' in each year. The change in 'Incremental Revenue Requirement from Previous Year' is calculated as the current year's incremental revenue requirement of the five-year capital plan less the previous year's incremental revenue requirement of the five-year capital plan.

The intent of these tables is to determine the revenue requirement impact of the forecasted five-year capital plan. A column for the year 2015 is not included as the forecasted five-year capital plan being evaluated runs from 2016-2020.

(h) AFUDC is a mechanism that defers the financing costs of building an asset so that these costs are recovered over the life of the asset. AFUDC is incurred while the project is considered construction work in progress and ceases once the asset becomes used and useful. These financing costs are then recovered over the life of the associated assets in order to "match" the costs to the periods in which the assets are providing benefit.

The financing costs that are incurred in support of building the assets is reflected in both interest expense and net earnings as NS Power's capital is financed by a combination of debt and equity. The AFUDC is an offsetting credit that reflects the fact that customers do not begin to pay for these financing costs until the assets become operational. These financing costs are then reflected as an increase to depreciation expense over the life of the associated assets.

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Request IR-10:

Please refer to page 56 of Exhibit N-1 showing a table of routine capital spending year-over-year. Given the large increases in transmission and distribution right-of-way widening investment, why does NSPI continue to classify this work as routine?

Response IR-10:

Please refer to NSUARB IR-35(a).

Request IR-11:

Please provide an updated 69kV Transmission Right-of-Way Widening Plan and explain all differences from Exhibit A-25 filed in M06321.

Response IR-11:

Please refer to Attachment 1, also provided electronically, for the updated 69kV Transmission Right-of-Way Widening Plan which includes the AO rates.

The only change from the Exhibit A-25 submission in M06321 is the inclusion of administrative overhead (AO) costs for labour, contracts and vehicles. This is a change in the base cost per year from $4.5 million to $5.4 million, for a total of $43.2 million (including AO) over 8 years.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

69kV Transmission Right-of-Way Widening Plan

Year	Line	Structure Type	Priority Group	Total Length (km)	Total Forested Edge[3] (km)	Total Widening Length (km)	New RoW Width (m)	Cost per Kilometre	RoW Widening Costs	Total Adjacent Properties	Estimated Easement Costs[6]	Total Widening Costs	Total Cost Per Year	Administrative Overhead (20.68%)	Total Cost with AO
2016	L-5023	H-Frame	A	1.2	0.36	0.72	40	$ 12,800	$ 9,167	4	$ 6,136	$ 15,303			
2016	L-5024	H-Frame	A	4.7	3.40	6.80	40	$ 12,800	$ 87,040	47	$ 72,098	$ 159,138			
2016	L-5039	H-Frame	A	9.52	4.60	9.20	40	$ 12,800	$ 117,760	17	$ 26,078	$ 143,838			
2016	L-5040	H-Frame	A	42.3	37.40	74.80	40	$ 12,800	$ 957,440	123	$ 188,682	$ 1,146,122	$ 4,534,929	$ 937,823	$ 5,472,753
2016	L-5054	H-Frame	A	23.4	21.00	42.00	40	$ 12,800	$ 537,600	193	$ 296,062	$ 833,662			
2016	L-5502	H-Frame	A	6.1	5.44	10.88	40	$ 12,800	$ 139,292	39	$ 59,826	$ 199,118			
2016	L-5510	H-Frame	A	71.1	63.90	127.80	40	$ 12,800	$ 1,635,840	262	$ 401,908	$ 2,037,748			
2017	L-5521	H-Frame	A	4.5	0.65	1.30	40	$ 12,800	$ 16,624	30	$ 46,020	$ 62,644			
2017	L-5524	H-Frame	A	35.4	29.00	58.00	40	$ 12,800	$ 742,400	75	$ 115,050	$ 857,450			
2017	L-5550	H-Frame	A	33.7	18.95	37.90	40	$ 12,800	$ 485,136	132	$ 202,488	$ 687,624			
2017	L-5559	H-Frame	A	38.7	32.80	65.60	40	$ 12,800	$ 839,680	224	$ 343,616	$ 1,183,296			
2017	L-5037	H-Frame	B	3.7	3.57	7.14	40	$ 12,800	$ 91,455	22	$ 33,748	$ 125,203	$ 4,448,916	$ 920,036	$ 5,368,951
2017	L-5055	H-Frame	B	20.8	17.00	34.00	40	$ 12,800	$ 435,200	45	$ 69,030	$ 504,230			
2017	L-5555	H-Frame	B	15.5	11.12	22.24	40	$ 12,800	$ 284,646	134	$ 205,556	$ 490,202			
2017	L-5025	H-Frame	C	30.2	8.02	16.05	40	$ 12,800	$ 205,389	217	$ 332,878	$ 538,267			
2018	L-5017	H-Frame	C	18.4	13.11	26.22	40	$ 12,800	$ 335,640	179	$ 274,586	$ 610,226			
2018	L-5053	H-Frame	C	25.7	20.70	41.40	40	$ 12,800	$ 529,920	240	$ 368,160	$ 898,080			
2018	L-5500	H-Frame	C	12.5	8.36	16.71	40	$ 12,800	$ 213,935	88	$ 134,992	$ 348,927			
2018	L-5501	H-Frame	C	7.6	1.80	3.60	40	$ 12,800	$ 46,111	39	$ 59,826	$ 105,937			
2018	L-5534	H-Frame	C	8.4	6.22	12.44	40	$ 12,800	$ 159,244	79	$ 121,186	$ 280,430			
2018	L-5564	H-Frame	C	19.1	11.23	22.45	40	$ 12,800	$ 287,411	79	$ 121,186	$ 408,597	$ 4,556,445	$ 942,273	$ 5,498,718
2018	L-5572	H-Frame	C	13.6	8.40	16.80	40	$ 12,800	$ 215,040	131	$ 200,954	$ 415,994			
2018	L-5573	H-Frame	C	15.8	9.90	19.80	40	$ 12,800	$ 253,440	158	$ 242,372	$ 495,812			
2018	L-5022	H-Frame	D	15.0	11.10	22.20	40	$ 12,800	$ 284,160	29	$ 44,486	$ 328,646			
2018	L-5019	H-Frame	D	3.4	3.10	6.20	40	$ 12,800	$ 79,360	6	$ 9,204	$ 88,564			
2018	L-5028	H-Frame	D	29.0	15.15	30.30	40	$ 12,800	$ 387,822	74	$ 113,516	$ 501,338			
2018	L-5035	H-Frame	D	0.8	0.61	1.22	40	$ 12,800	$ 15,602	38	$ 58,292	$ 73,894			
2019	L-5026	H-Frame	C	47.5	19.16	38.32	40	$ 12,800	$ 490,555	204	$ 312,936	$ 803,491			
2019	L-5003	H-Frame	D	13.5	5.85	11.69	40	$ 12,800	$ 149,692	114	$ 174,876	$ 324,568			
2019	L-5004	H-Frame	D	12.1	6.90	13.80	40	$ 12,800	$ 176,640	37	$ 56,758	$ 233,398			
2019	L-5011	H-Frame	D	9.3	5.20	10.40	40	$ 12,800	$ 133,120	35	$ 53,690	$ 186,810			
2019	L-5029	H-Frame	D	20.2	16.23	32.47	40	$ 12,800	$ 415,603	83	$ 127,322	$ 542,925			
2019	L-5031	H-Frame	D	19.8	19.45	38.90	40	$ 12,800	$ 497,977	95	$ 145,730	$ 643,707	$ 4,500,949	$ 930,796	$ 5,431,745
2019	L-5047	H-Frame	D	3.1	0.20	0.39	40	$ 12,800	$ 5,014	10	$ 15,340	$ 20,354			
2019	L-5048	H-Frame	D	5.5	4.37	8.75	40	$ 12,800	$ 111,970	65	$ 99,710	$ 211,680			
2019	L-5058	H-Frame	D	39.3	33.40	66.80	40	$ 12,800	$ 855,040	115	$ 176,410	$ 1,031,450			
2019	L-5505	H-Frame	D	11.5	9.10	18.20	40	$ 12,800	$ 232,960	83	$ 127,322	$ 360,282			
2019	L-5537	H-Frame	D	3.4	3.22	6.44	40	$ 12,800	$ 82,457	39	$ 59,826	$ 142,283			
2020	L-5539	H-Frame	D	8.4	5.44	10.87	40	$ 12,800	$ 139,150	88	$ 134,992	$ 274,142			
2020	L-5548	H-Frame	D	17.1	4.46	8.91	40	$ 12,800	$ 114,065	57	$ 87,438	$ 201,503			
2020	L-5551	H-Frame	D	9.7	6.23	12.46	40	$ 12,800	$ 159,506	94	$ 144,196	$ 303,702			
2020	L-5571	H-Frame	D	6.4	3.80	7.59	40	$ 12,800	$ 97,203	34	$ 52,156	$ 149,359			
2020	L-5575	H-Frame	D	12.6	8.20	16.40	40	$ 12,800	$ 209,863	75	$ 115,050	$ 324,913			
2020	L-5579	H-Frame	D	41.1	38.50	77.00	40	$ 12,800	$ 985,600	305	$ 467,870	$ 1,453,470			
2020	L-5044	Single Pole	A	3.8	3.37	6.75	30	$ 11,070	$ 74,698	44	$ 67,496	$ 142,194	$ 4,436,503	$ 917,469	5,353,972
2020	L-5506	Single Pole	A	8.4	4.41	8.82	30	$ 11,070	$ 97,604	97	$ 148,798	$ 246,402			
2020	L-5511	Single Pole	A	31.7	28.00	56.00	30	$ 11,070	$ 619,920	130	$ 199,420	$ 819,340			
2020	L-5533	Single Pole	A	13.1	7.86	15.71	30	$ 11,070	$ 173,956	89	$ 136,526	$ 310,482			
2020	L-5538	Single Pole	A	7.5	4.67	9.34	30	$ 11,070	$ 103,412	44	$ 67,496	$ 170,908			
2020	L-5036	Single Pole	B	3.4	0.11	0.22	30	$ 11,070	$ 2,429	5	$ 7,670	$ 10,099			
2020	L-5508	Single Pole	B	1.7	0.52	1.05	30	$ 11,070	$ 11,581	12	$ 18,408	$ 29,989			
2021	L-5014	Single Pole	A	10.8	2.67	5.34	30	$ 11,070	$ 59,117	19	$ 29,146	$ 88,263			
2021	L-5033	Single Pole	A	12.2	6.70	13.40	30	$ 11,070	$ 148,338	57	$ 87,438	$ 235,776			
2021	L-5046	Single Pole	A	2.7	1.19	2.38	30	$ 11,070	$ 26,380	30	$ 46,020	$ 72,400			
2021	L-5545	Single Pole	A	5.2	2.67	5.34	30	$ 11,070	$ 59,117	53	$ 81,302	$ 140,419			
2021	L-5546	Single Pole	A	12.5	6.87	13.75	30	$ 11,070	$ 152,201	128	$ 196,352	$ 348,553	$ 4,452,524	$ 920,782	$ 5,373,305
2021	L-5565	Single Pole	A	18.9	16.80	33.60	30	$ 11,070	$ 371,952	106	$ 162,604	$ 534,556			
2021	L-5027	Single Pole	C	104.5	92.30	184.60	30	$ 11,070	$ 2,043,522	255	$ 391,170	$ 2,434,692			
2021	L-5561A	Single Pole	C	15.0	11.22	22.44	30	$ 11,070	$ 248,383	105	$ 161,070	$ 409,453			
2021	L-5016	Single Pole	D	6.7	5.60	11.20	30	$ 11,070	$ 123,984	42	$ 64,428	$ 188,412			
2022	L-5015	Single Pole	A	19.0	15.90	31.80	30	$ 11,070	$ 352,026	87	$ 133,458	$ 485,484			
2022	L-5021	Single Pole	A	7.2	5.20	10.40	30	$ 11,070	$ 115,128	56	$ 85,904	$ 201,032			
2022	L-5020	Single Pole	D	9.2	8.90	17.80	30	$ 11,070	$ 197,046	51	$ 78,234	$ 275,280			
2022	L-5030	Single Pole	D	2.9	0.71	1.41	30	$ 11,070	$ 15,647	8	$ 12,272	$ 27,919			
2022	L-5056	Single Pole	D	4.0	3.10	6.20	30	$ 11,070	$ 68,634	14	$ 21,476	$ 90,110	$ 4,546,020	$ 940,117	$ 5,486,137
2022	L-5057	Single Pole	D	2.2	1.35	2.71	30	$ 11,070	$ 29,995	5	$ 7,670	$ 37,665			
2022	L-5512	Single Pole	D	6.5	5.70	11.40	30	$ 11,070	$ 126,198	52	$ 79,768	$ 205,966			
2022	L-5531	Single Pole	D	23.9	20.10	40.20	30	$ 11,070	$ 445,014	89	$ 136,526	$ 581,540			
2022	L-5532	Single Pole	D	96.3	87.00	174.00	30	$ 11,070	$ 1,926,180	466	$ 714,844	$ 2,641,024			
2023	L-5050	Single Pole	D	15.9	15.40	30.80	30	$ 11,070	$ 340,956	54	$ 82,836	$ 423,792			
2023	L-5530	Single Pole	D	67.5	39.40	78.80	30	$ 11,070	$ 872,316	155	$ 237,770	$ 1,110,086			
2023	L-5535	Single Pole	D	64.3	58.30	116.60	30	$ 11,070	$ 1,290,762	420	$ 644,280	$ 1,935,042	$ 4,512,412	$ 933,167	$ 5,445,578
2023	L-5536	Single Pole	D	20.2	12.49	24.99	30	$ 11,070	$ 276,632	170	$ 260,780	$ 537,412			
2023	L-5547	Single Pole	D	19.5	10.94	21.88	30	$ 11,070	$ 242,231	172	$ 263,848	$ 506,079			
Total				**1406.97**	**1036.06**	**2072.12**			**$ 24,864,129**	**7252**	**$ 11,128,194**	**$ 35,988,697**			

Notes:

1. Assume that all properties are less than one acre (based upon sample size).
2. Assume that the land on both sides of the right-of-way is on one property.
3. Assume linear km of right-of-way with forested edge (2 sided).
4. Assume that the Land Agent does not have to make repeated visits to negoiate settlement.
5. Assume for properties > 1 acre, the costs of the easements will not exceed $0.25M.
6. Assume average total of $1,534 per property for Estimated Easement Costs: includes an average of $1,005 per acre for land easements, plus $82.50/hr for Land Agent assessment for an average of 6 hours per property, plus an average of $34 per property for land valuation for a project of this magnitude.
7. Transmission lines can be re-prioritized within a planned year based upon additional criteria of operational efficiencies and line performance.
8. Transmission lines may span multiple years in the work plan

NON-CONFIDENTIAL

Request IR-12:

Please refer to page 64 of Exhibit N-1, which lists a total of $5.4 million in 69 kV transmission right-of-way widening, whereas page 65 of the same document states actual widening for 69kV right-of-ways is $4.5 million. Exhibit A-25 filed in M06321 also references $4.5 million in annual right-of-way widening expenditure. Please explain the reason for the increased expenditure.

Response IR-12:

As stated in SBA IR-11 and noted on page 65 of the 2016 ACE Plan, the difference in the annual totals is due to administrative overhead (AO). The $4.5 million per year included in Exhibit A-25 filed in M06321 did not include AO amounts as the analysis was focused on straight contractor widening costs. Once AO is included, the cost per year is $5.4 million for 8 years to widen all of the 69kV transmission rights-of-way in the province.

NON-CONFIDENTIAL

Request IR-13:

Please refer to page 72 of Exhibit N-1. Please define in detail the scope of the annual $10.4 million figure for vegetation management.

Response IR-13:

The scope of the annual vegetation management program is described in the table below. This amount includes the $3 million in the Distribution Right-of-Way Routine (D010), as those projects will establish new rights-of-way beyond the current width. The 69kV Right-of-Way Widening routine is not included in these totals as that $5.4 million project is above and beyond the base vegetation program.

	2016 ($)	**Financial**
Reactive Tree Trimming (Distribution)	350,000	Operating
Preventative Veg Management (Distribution)	1,750,000	Operating
Urban Cycle (Distribution)	500,000	Operating
Sustainable (Distribution)	500,000	Operating
Hazard Tree Removal (Distribution)	500,000	Operating
Customer Requested (Distribution)	1,000,000	Operating
ROW Widening/Establishment (Distribution)	3,000,000	Capital
Distribution Subtotal	*7,600,000*	
Veg Management & Sustainable (Transmission)	2,800,000	Operating
Total Vegetation Management	**10,400,000**	

NON-CONFIDENTIAL

Request IR-14:

Please provide a list of all of Nova Scotia's generating units greater than 10 MW in capacity with each unit's:

(a) Summer and Winter capacity

(b) Fuel type

(c) Annual capacity factor for the past 3 calendar years

(d) Full load heat rate

Response IR-14:

(a-d) Please refer to Attachment 1, also provided electronically.

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		A)		B)	C)			D)
Unit	Type	Summer Capacity (MW)	Winter Capacity (MW)	Fuel Type	Capacity Factor 2013	Capacity Factor 2014	Capacity Factor 2015	Full Load Heat Rate
Tufts Cove 1	Thermal	81	81	Nat Gas/HFO	18%	37%	23%	10711
Tufts Cove 2	Thermal	93	93	Nat Gas/HFO	25%	51%	39%	10668
Tufts Cove 3	Thermal	147	147	Nat Gas/HFO	44%	26%	41%	10230
Pt. Aconi 1	Thermal	171	171	Coal	81%	72%	76%	10591
Lingan 1	Thermal	153	153	Coal	65%	52%	52%	10237
Lingan 2	Thermal	153	153	Coal	59%	50%	29%	10246
Lingan 3	Thermal	153	153	Coal	56%	34%	40%	10190
Lingan 4	Thermal	153	153	Coal	69%	60%	58%	10037
Trenton 5	Thermal	135	150	Coal	48%	59%	59%	9993
Trenton 6	Thermal	157	157	Coal	80%	82%	78%	10007
Pt. Tupper 2	Thermal	152	152	Coal	61%	77%	74%	9855
Burnside 1	Combustion Turbines	24.9	30.1	HFO	0.3%	1.1%	1.2%	11678
Burnside 2	Combustion Turbines	24.9	30.5	HFO	0.6%	1.1%	1.3%	11678
Burnside 3	Combustion Turbines	24.9	30.0	HFO	0.5%	0.1%	0.5%	11678
Burnside 4	Combustion Turbines	24.9	30.0	HFO	0.0%	0.0%	0.0%	11678
Victoria Junction 1	Combustion Turbines	24.9	30.1	HFO	0.0%	0.1%	0.1%	11678
Victoria Junction 2	Combustion Turbines	24.9	30.0	HFO	0.1%	0.1%	0.0%	11678
Tusket	Combustion Turbines	24.9	23.8	HFO	0.1%	0.1%	0.0%	13435
Tufts Cove 4	Combustion Turbines	49.5	49	Nat Gas	46%	50%	49%	9826
Tufts Cove 5	Combustion Turbines	49.5	49	Nat Gas	45%	54%	50%	9826
Tufts Cove 6	Heat Recovery	50.8	50.8	Combined Cycle	23%	32%	23%	8256
Wreck Cove 1	Hydro	106	106	Hydro	23%	22%	17%	-
Wreck Cove 2	Hydro	106	106	Hydro	12%	14%	14%	-
Port Hawkesbury	Biomass	45	45	Wood Product			41%	-
Annapolis	Hydro	19	19	Hydro	9%	9%	8%	-
Lequille	Hydro	11.2	11.2	Hydro	27%	36%	27%	-

*New engine (installed in 2013) in Tusket is yet to be tested, however its capacity is expected to be the same as the other combustion turbine units.

Request IR-15:

For each generating unit modeled in NSPI's EAM, please provide the following:

(a) Expected delivered fuel cost in $/MMBtu for the next five years

(b) Estimated total full load dispatch cost for the next five years

Response IR-15:

(a) Please refer to Partially Confidential Attachment 1, also provided electronically.

(b) This information cannot be provided as the estimated total full load dispatch cost will depend on the fuel blend for each unit. This information is not used within the EAM.

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Unit	Fuel Type	Delivered Price ($/MMBtu) 2016	2017	2018	2019	2020
Lingan 1	LS-HBTU	[redacted]				
Lingan 1	LS-LBTU					
Lingan 1	MS					
Lingan 1	PC6					
Lingan 1	PRB					
Lingan 2	LS-HBTU					
Lingan 2	LS-LBTU					
Lingan 2	MS					
Lingan 2	PC6					
Lingan 2	PRB					
Lingan 3	LS-HBTU					
Lingan 3	LS-LBTU					
Lingan 3	MS					
Lingan 3	PC6					
Lingan 3	PRB					
Lingan 3	LS-HBTU					
Lingan 4	LS-LBTU					
Lingan 4	MS					
Lingan 4	PC6					
Lingan 4	PRB					
Point Aconi	LS-LBTU					
Point Aconi	PC6					
Point Aconi	PRB					
Point Tupper	LS-HBTU					
Point Tupper	LS-LBTU					
Point Tupper	MS					
Point Tupper	PC6					
Point Tupper	PRB					
Trenton 5	LS-HBTU					
Trenton 5	LS-LBTU					
Trenton 5	MS					
Trenton 6	LS-HBTU					
Trenton 6	LS-LBTU					
Trenton 6	MS					
Trenton 6	PC6					
Trenton 6	NOVA					

Legend

LS-HBTU	Low Sulphur - High BTU
LS-LBTU	Low Sulphur - Low BTU
MS	Mid Sulphur
PC6	Pet Coke
PRB	Powder River Basin
NOVA	Nova Coal

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Tufts Cove 1 - 6

Year	Month	Natural Gas Price ($/MMBtu)	HFO Price ($/MMBtu)
2016	1	[redacted]	[redacted]
2016	2		
2016	3		
2016	4		
2016	5		
2016	6		
2016	7		
2016	8		
2016	9		
2016	10		
2016	11		
2016	12		
2017	1		
2017	2		
2017	3		
2017	4		
2017	5		
2017	6		
2017	7		
2017	8		
2017	9		
2017	10		
2017	11		
2017	12		
2018	1		
2018	2		
2018	3		
2018	4		
2018	5		
2018	6		
2018	7		
2018	8		
2018	9		
2018	10		
2018	11		
2018	12		
2019	1		
2019	2		
2019	3		
2019	4		
2019	5		
2019	6		
2019	7		
2019	8		
2019	9		
2019	10		
2019	11		
2019	12		
2020	1		
2020	2		
2020	3		
2020	4		
2020	5		
2020	6		
2020	7		
2020	8		
2020	9		
2020	10		
2020	11		
2020	12		

Request IR-16:

Please describe how the replacement energy cost assumptions used in the EAM for the 2016 ACE Plan were derived. Please describe all changes from the replacement cost assumptions used in the EAMs filed in support of the 2015 ACE Plan.

Response IR-16:

Replacement Energy Costs (REC) for 2016-2020 were calculated based on Plexos simulations, without PHP load, completed in Q1 2015.

The REC methodology consists of the following steps:

(1) For each thermal unit, as well as imports, monthly average cost ($/MWh) and monthly total output (GWh) are compiled from the Plexos simulation outputs.

(2) Energy-weighted average prices for the summer (April 1 – October 31) and winter (November 1 – March 31) periods are calculated for each thermal unit, as well as imports.

(3) For each unit or unit grouping for which a REC is needed, a calculation is performed to find the difference in seasonal energy-weighted average production cost between the unit itself and the energy-weighted average of the unit(s) that are eligible to replace that energy, under normal system dispatch conditions. Specifically:

(a) Coal units: Energy from these units can be replaced by any other generating unit, except those that are fully dispatched (defined as having a forecasted net capacity factor greater than 70 percent). For the purpose of this calculation, the four Lingan units are combined into a single energy-weighted average.

(b) Tufts Cove Combined Cycle (CC): Energy from these units can be replaced by Tufts Cove steam units and diesel CTs in the winter, and by Tufts Cove steam units as well as imports in the summer (winter transmission constraints limit the ability of imports to offset Tufts Cove generation).

(c) Tufts Cove Steam units: Energy from these units can be replaced by other Tufts Cove steam units and diesel CTs in the winter; imports are also available in the summer. It is assumed that Tufts Cove CC unit is already fully dispatched if TUC steam energy is required; therefore the CC is not an eligible replacement unit.

(d) Diesel Combustion Turbines: If diesel CT energy is required, it is assumed that all other energy sources on the system are fully dispatched or unavailable. Therefore this energy can be replaced by an equivalent import from NB, plus three percent to account for transmission losses from NB border to NS load centre.

(e) Hydro: Hydro generation can be replaced by any other dispatchable generator on the system, other than those that are fully dispatched (defined as having a forecasted capacity factor greater than 70 percent).

(4) The seasonal replacement energy costs calculated in step 3 for each unit or unit grouping are then combined into a single annual value by taking the energy-weighted average of the summer and winter values. These annual costs are then input to the EAM model.

The 2016 ACE Plan REC for hydro has been updated and is now calculated from annual hydro generation provided from the Plexos results rather than the sum of all generation, which was used in the 2015 ACE Plan. 2015 ACE Plan replacement energy costs were based on average marginal costs, while 2016 replacement energy costs were based on average cost of production. Due to larger quantity of wind generation in 2016 and declining system load, average marginal costs that were used in 2015 ACE Plan REC were not suitable for the 2016 forecast due to additional low load wind curtailment and wind integration operational effects on marginal costs.

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Request IR-17:

Please provide any natural gas price assumptions relied upon to generate replacement energy cost estimates for the EAM used to support the 2016 ACE Plan.

Response IR-17:

Please refer to Partially Confidential Attachment 1, also provided electronically.

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Natural Gas Prices used in Replacement Energy Costs Plexos Model

Date From	Price ($/MMBTU)
01/01/2016	[redacted]
02/01/2016	[redacted]
03/01/2016	[redacted]
04/01/2016	[redacted]
05/01/2016	[redacted]
06/01/2016	[redacted]
07/01/2016	[redacted]
08/01/2016	[redacted]
09/01/2016	[redacted]
10/01/2016	[redacted]
11/01/2016	[redacted]
12/01/2016	[redacted]
13/01/2016	[redacted]
14/01/2016	[redacted]
15/01/2016	[redacted]
16/01/2016	[redacted]
17/01/2016	[redacted]
18/01/2016	[redacted]
19/01/2016	[redacted]
20/01/2016	[redacted]
21/01/2016	[redacted]
22/01/2016	[redacted]
23/01/2016	[redacted]
24/01/2016	[redacted]
25/01/2016	[redacted]
26/01/2016	[redacted]
27/01/2016	[redacted]
28/01/2016	[redacted]
29/01/2016	[redacted]
30/01/2016	[redacted]
31/01/2016	[redacted]
01/02/2016	[redacted]
02/02/2016	[redacted]
03/02/2016	[redacted]
04/02/2016	[redacted]
05/02/2016	[redacted]
06/02/2016	[redacted]
07/02/2016	[redacted]
08/02/2016	[redacted]
09/02/2016	[redacted]
10/02/2016	[redacted]
11/02/2016	[redacted]
12/02/2016	[redacted]
13/02/2016	[redacted]
14/02/2016	[redacted]
15/02/2016	[redacted]
16/02/2016	[redacted]
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22/02/2016	[redacted]
23/02/2016	[redacted]
24/02/2016	[redacted]
25/02/2016	[redacted]
26/02/2016	[redacted]
27/02/2016	[redacted]
28/02/2016	[redacted]
29/02/2016	[redacted]
01/03/2016	[redacted]
01/04/2016	[redacted]
01/05/2016	[redacted]
01/06/2016	[redacted]
01/07/2016	[redacted]
01/08/2016	[redacted]
01/09/2016	[redacted]
01/10/2016	[redacted]
01/11/2016	[redacted]
01/12/2016	[redacted]
02/12/2016	[redacted]
03/12/2016	[redacted]
04/12/2016	[redacted]

Date From	Price ($/MMBTU)
05/12/2016	[redacted]
06/12/2016	[redacted]
07/12/2016	[redacted]
08/12/2016	[redacted]
09/12/2016	[redacted]
10/12/2016	[redacted]
11/12/2016	[redacted]
12/12/2016	[redacted]
13/12/2016	[redacted]
14/12/2016	[redacted]
15/12/2016	[redacted]
16/12/2016	[redacted]
17/12/2016	[redacted]
18/12/2016	[redacted]
19/12/2016	[redacted]
20/12/2016	[redacted]
21/12/2016	[redacted]
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27/12/2016	[redacted]
28/12/2016	[redacted]
29/12/2016	[redacted]
30/12/2016	[redacted]
31/12/2016	[redacted]
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02/01/2017	[redacted]
03/01/2017	[redacted]
04/01/2017	[redacted]
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06/01/2017	[redacted]
07/01/2017	[redacted]
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27/01/2017	[redacted]
28/01/2017	[redacted]
29/01/2017	[redacted]
30/01/2017	[redacted]
31/01/2017	[redacted]
01/02/2017	[redacted]
02/02/2017	[redacted]
03/02/2017	[redacted]
04/02/2017	[redacted]
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10/02/2017	[redacted]
11/02/2017	[redacted]
12/02/2017	[redacted]
13/02/2017	[redacted]
14/02/2017	[redacted]
15/02/2017	[redacted]
16/02/2017	[redacted]
17/02/2017	[redacted]

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Date From	Price ($/MMBTU)
18/02/2017	[redacted]
19/02/2017	[redacted]
20/02/2017	[redacted]
21/02/2017	[redacted]
22/02/2017	[redacted]
23/02/2017	[redacted]
24/02/2017	[redacted]
25/02/2017	[redacted]
26/02/2017	[redacted]
27/02/2017	[redacted]
28/02/2017	[redacted]
01/03/2017	[redacted]
01/04/2017	[redacted]
01/05/2017	[redacted]
01/06/2017	[redacted]
01/07/2017	[redacted]
01/08/2017	[redacted]
01/09/2017	[redacted]
01/10/2017	[redacted]
01/11/2017	[redacted]
01/12/2017	[redacted]
02/12/2017	[redacted]
03/12/2017	[redacted]
04/12/2017	[redacted]
05/12/2017	[redacted]
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07/12/2017	[redacted]
08/12/2017	[redacted]
09/12/2017	[redacted]
10/12/2017	[redacted]
11/12/2017	[redacted]
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13/12/2017	[redacted]
14/12/2017	[redacted]
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23/12/2017	[redacted]
24/12/2017	[redacted]
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26/12/2017	[redacted]
27/12/2017	[redacted]
28/12/2017	[redacted]
29/12/2017	[redacted]
30/12/2017	[redacted]
31/12/2017	[redacted]
01/01/2018	[redacted]
02/01/2018	[redacted]
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05/01/2018	[redacted]
06/01/2018	[redacted]
07/01/2018	[redacted]
08/01/2018	[redacted]
09/01/2018	[redacted]
10/01/2018	[redacted]
11/01/2018	[redacted]
12/01/2018	[redacted]
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14/01/2018	[redacted]
15/01/2018	[redacted]
16/01/2018	[redacted]
17/01/2018	[redacted]
18/01/2018	[redacted]
19/01/2018	[redacted]
20/01/2018	[redacted]
21/01/2018	[redacted]
22/01/2018	[redacted]
23/01/2018	[redacted]
24/01/2018	[redacted]

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Date From	Price ($/MMBTU)
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Request IR-18:

Please provide an outage plan for all units for 2015 and the two years prior and after.

(a) For each unit, please provide the maintenance projects that have been completed or are planned to be completed and the length of time needed for each project.

(b) For each planned outage, please provide the main reason for the outage.

Response IR-18:

(a) Outage charters are attached for 2014, 2015, and 2016. 2017 charters are in approval stage at this time. Outage timelines are defined in the respective charter. Individual elements or projects within each outage are optimized within the duration of the outage.

(b) The main reason(s) for each outage are outlined in the respective Charter. Please refer to the following attachments:

Attachment 1	2014 Charter (Biomass)
Attachment 2	2014 Charter (Lingan)
Attachment 3	2014 Charter (Point Aconi)
Attachment 4	2014 Charter (Point Tupper)
Attachment 5	2014 Charter (Trenton)
Attachment 6	2014 Charter (Tufts Cove)
Attachment 7	2015 LIN Charter Signed
Attachment 8	2015 PHB Charter Signed
Attachment 9	2015 POA Charter Signed
Attachment 10	2015 POT Charter Signed
Attachment 11	2015 TRE Outage Charter Signed
Attachment 12	2015 TUC Charter Signed
Attachment 13	2016 Outage Charter Signed – Lingan 1
Attachment 14	2016 Outage Charter Signed – Lingan 2
Attachment 15	2016 Outage Charter Signed – Lingan 3
Attachment 16	2016 Outage Charter Signed – Lingan 4

Attachment 17	2016 Outage Charter Signed – PH Biomass
Attachment 18	2016 Outage Charter Signed – Point Aconi
Attachment 19	2016 Outage Charter Signed – Point Tupper
Attachment 20	2016 Outage Charter Signed – Trenton 5
Attachment 21	2016 Outage Charter Signed – Trenton 6
Attachment 22	2016 Outage Charter Signed – Tufts Cove 1
Attachment 23	2016 Outage Charter Signed – Tufts Cove 2
Attachment 24	2016 Outage Charter Signed – Tufts Cove 3
Attachment 25	2016 Outage Charter Signed – Tufts Cove 6
Attachment 26	2016 Outage Charters Signed – Burnside Combustion Turbines
Attachment 27	2016 Outage Charters Signed – Tufts Cove Combustion Turbines
Attachment 28	2016 Outage Charters Signed – Tusket Combustion Turbines
Attachment 29	2016 Outage Charters Signed – VJ Combustion Turbines

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SHUTDOWN CHARTER	
Project Name	2014 Shutdown Charter
Executive Owner	Dave Pickles
Shutdown Owner	Jeff Campbell
Shutdown Manager	Ray Barrett

BACKGROUND INFORMATION

The Charter is based on the Standardized Shutdown TMP. It Identifies our major Shutdown Deliverables for 2014 and provides a high level overview.

In 2014 there are a number of Capital projects and inspections which will require the generating unit to be shutdown. Some of the capital projects are for life extensions and reliability. The inspections are time stamped, some by the O.E.M. and others by plant operating practices. Both of these are influenced either by Thermal Maintenance Practices or the Life Cycle Management programs of each plant. This work is also influenced by the Reliability Asset Health assessments.

These Major Items are Identified through review of previous shutdown inspections, asset health assessments, equipment maintenance, operating history, and regulatory time stamped requirements.

SAFETY PLAN

1) Pt. Tupper Bio Mass is committed to an accident free work place and will be committing to early identification & mitigation any risks that pose a threat to employee safety.

2) Safety Stand Down will be coordinated early in the outage schedule, engaging all staff & contractors.

3) Safety person will be utilized on outages to assisting in promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, and incident reporting.

4) Shutdown Preparation will ensure that equipment and work Areas are properly inspected and safe for use before shutdown begins (Housekeeping, Cranes, Lifting Gear, Lighting, vehicles, etc.)

5) Safety Issues and concerns will be discussed with Shutdown leads during planned shutdown meetings.

6) All aspects of the safety program will be maintained during the Shutdown.

7) All Safety Documentation (Incident Reports, Observation Reports, Etc.) managed by the shutdown safety person will be recorded along with the Shutdown Report for history purposes.

8) A pre-return to service walk down inspection and sign-off will be completed prior to hand-off to Operations (Staging, Insulation, Combustibles, and Obstructions).

9) Plant Cleanups will be conducted during and after Shutdowns as required to ensure that the Plant remains Clean & Safe to work in.

SHUTDOWN OBJECTIVES	
1	Accident Free
2	Execute the planned work during the outages safely, on-time and on-budget.
3	At Least 90% Completion Rate of Plant Shutdown Schedule (Projects, Preventative, Issues)
4	Address all known plant issues that affect unit reliability, performance and heat rate.

ROLE	RESPONSIBILITIES
Executive Owner	Provides the leadership, priority and commitment to the shutdown scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the shutdown objectives and assuring proper resourcing.
Shutdown Owner	Actively champions and promotes the shutdown work scope. Clarifies Shutdown objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the shutdown manager. Helps remove obstacles to success.
Shutdown Manager	Has overall accountability for the successful execution of the maintenance shutdown in terms of scope, cost, schedule, and quality and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other shutdown resources. Continually ensures effective communication with key shutdown stakeholders. Proactively monitors shutdown performance and ensures appropriate action is taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

UNIT OUTAGE OVERVIEW

For Pt. Tupper Bio Mass in 2014 the Thermal Maintenance Outage year looks like:

PHB – Major Shutdown (3 Weeks 2nd Q 2014)

- Kablitz Water Cool Beams (cap)
- boiler grates fixed (cap)
- Boiler grates moving (cap)
- Bottom Boiler grates Cap)
- CW culvert Inspection/Cleaning (OM&GI)
- Bottom ash sealing screw (cap)
- Precip inspection(OM&GI)
- Precip screws and troughs (CAP)
- 50% transel screwsreplacement (cap)
- Sprockets and chains for above (cap)
- TMP compliance deferred 2015
- PM shutdown compliance
- regulatory
- Fuel system maint
- Distributing conveyor
- Bottom ash conveyor
- Superheater inspection
- Tube reconfiguration from leak repair on Aug 1
- Ash bunker work

MAJOR DELIVERABLES	
1	Draft Scope of Shutdown Capital Projects & Maintenance Inspections / Repairs is developed with time & cost Estimates for Labor Staffing and accurate Budgeting.
2	Validate scope of work with Asset Experts, Asset Management Group, OEMs, Etc.
3	Known required (long lead) materials procured in advance and ETA tracked to delivery.
4	Have all contract work identified and RFP's / RFQ's drafted for release allowing time for terms and conditions to be finalized. (+$1M)

ASSUMPTIONS

Economic outages will be assessed as they occur and the ability to reduce scope for the original outage will result on a case by case basis. Opportunities may exist to reduce term labour.

	MILESTONES	Date
1	End of Q1 – Finalized work plan, draft capital list, draft budget	NA

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2	End of Q2 – Finalized capital plan, more accurate work scope (labour plan) and budget	NA
3	End of Q3 – Finalized budget, capital program and maintenance scope.	September 30, 2013

HIGH LEVEL OM&G BUDGET		Amount
1	Unit PHB – Major Shutdown (3Weeks 2nd Q 2014)	750K
	Total Budget	750K

HIGH LEVEL CAPITAL BUDGET		Amount
	Boiler	750K
	Analytical Panel	106K
	Valve isolation	75K
	STG control upgrades	35K
	Dust Mitigation in Elect Rms	28K
	PHB - Stacker Upgrade	100K
		1.094

MAJOR RISKS		Probability (H,M,L)	Impact to Project (H,M,L)
	Unforeseen findings when boiler is inspected	M	M
Define mitigation and / or contingency strategies where Probability or Impact are High:			

AGREED			
Shutdown Manager	Raymond Barrett	**Date**	
Shutdown Owner		**Date**	
Executive Owner		**Date**	

SHUTDOWN CHARTER	
Project Name	2014 Shutdown Charter
Executive Owner	Dave Pickles
Shutdown Owner	Brad George
Shutdown Manager	Stewart Whynott

BACKGROUND INFORMATION

The Charter is based on the Standardized Shutdown TMP. It Identifies our major Shutdown Deliverables for 2014 and provides a high level overview.

In 2014 there are a number of Capital projects and inspections which will require the generating units to be shutdown. Some of the capital projects are for life extensions and reliability. The inspections are time stamped, some by the O.E.M. and others by plant operating practices. Both of these are influenced either by Thermal Maintenance Practices or the Life Cycle Management programs of each plant. This work is also influenced by the Reliability Asset Health assessments.

These Major Items are Identified through review of previous shutdown inspections, asset health assessments, equipment maintenance, operating history, and regulatory time stamped requirements.

SAFETY PLAN

1) Lingan Generating Station is committed to an accident free work place and will be committing to early identification and mitigation any risks that pose a threat to employee safety.

2) Safety Stand Down will be coordinated early in the outage schedules, engaging all staff and contractors.

3) A safety person will be utilized on outages to assist promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, and incident reporting.

4) Shutdown Preparation will ensure that equipment and work areas are properly inspected and safe for use before shutdown begins (Housekeeping, Cranes, Lifting Gear, Lighting, vehicles, etc.)

5) Safety Issues and concerns will be discussed with Shutdown leads during planned shutdown meetings.

6) All aspects of the safety program will be maintained during the Shutdown.

7) All Safety Documentation (Incident Reports, Observation Reports, Etc.) managed by the shutdown safety person will be recorded along with the Shutdown Report for history purposes.

8) A pre-return to service walk down inspection and sign-off will be completed prior to hand-off to Operations (Staging, Insulation, Combustibles, and Obstructions).

9) Plant Cleanups will be conducted after Shutdowns as required to ensure that the Plant remains Clean and Safe to work in.

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SHUTDOWN OBJECTIVES	
1	Accident Free
2	Execute the planned work during the outages safely, on-time and on-budget.
3	At Least 85% Completion Rate of Plant Shutdown Schedule (Projects, Preventative, Issues)
4	If feasible, address all known plant issues that affect unit reliability, performance and heat rate.

ROLE	RESPONSIBILITIES
Executive Owner	Promotes Health and Safety during Shutdowns Provides the leadership, priority and commitment to the shutdown scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the shutdown objectives and assuring proper resourcing.
Shutdown Owner	Promotes Health and Safety during Shutdowns Actively champions and promotes the shutdown work scope. Clarifies Shutdown objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the shutdown manager. Helps remove obstacles to success.
Shutdown Manager	Promotes Health and Safety during Shutdowns Has overall accountability for the successful execution of the maintenance shutdown in terms of scope, cost, schedule, and quality and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other shutdown resources. Continually ensures effective communication with key shutdown stakeholders. Proactively monitors shutdown performance and ensures appropriate action is taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

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UNIT OUTAGE OVERVIEW

For Lingan GS in 2014 the Thermal Maintenance Outage year looks like:

Unit 1 – Minor Shutdown (2 Weeks Spring 2014)

- Boiler inspection.
- L-0 blade inspection.
- Routine outage work/inspection/PM.
- Layup (pending)

Unit 2 – Minor Shutdown (2 Weeks Spring 2014)

- Boiler inspection.
- L-0 blade inspection.
- Routine outage work/inspection/PM.
- Layup (pending)

Unit 3 – Major Shutdowns (1 Weeks Fall 2014)

- LP blade inspection
- Boiler inspection
- Minor Repairs

Unit 4 – Minor Shutdown (2weeks Fall 2014)

- Boiler inspection.
- L-0 blade inspection.
- Routine outage work/inspection/PM.

MAJOR DELIVERABLES

1	Draft scope of shutdown capital projects & maintenance inspections / repairs is developed with time & cost estimates for labor staffing and accurate budgeting.
2	Validate scope of work with Asset Experts, Asset Management Group, OEMs, Etc.
3	Known required (long lead) materials procured in advance and ETA tracked to delivery.
4	Have all contract work identified and RFP's / RFQ's drafted for release allowing time for terms and conditions to be finalized. (+$1M)

ASSUMPTIONS

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Economic outages will be assessed as they occur and the ability to reduce scope for the original outage will result on a case by case basis. Opportunities may exist to reduce term labour.
Unit 1 and 2 will be ABNO *(pending)*

MILESTONES		Date
1	End of Q1 – Finalized work plan, draft capital list, draft budget	March 31, 2013
2	End of Q2 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2013
3	End of Q3 – Finalized budget, capital program and maintenance scope.	September 30, 2013

HIGH LEVEL OM&G BUDGET		Amount
1	Unit 1 – Minor Shutdown (2 Weeks Spring 2014)	492K
2	Unit 2 – Minor Shutdown (2 Weeks Spring 2014)	472K
3	Unit 3 – Major Shutdown (1 Weeks Fall 2014)	380K
4	Unit 4 – Minor Shutdown (2 weeks Fall 2014)	472K
	Total Budget	1818K

HIGH LEVEL CAPITAL BUDGET		Amount
1	Unit 1 – Minor Shutdown (2 Weeks Spring 2014)	1460K
2	Unit 2 – Minor Shutdown (2 Weeks Spring 2014)	100K.
3	Unit 3 – Minor Shutdown (1 Weeks Spring 2014)	1750K
4	Unit 4 – Minor Shutdown (2 weeks Fall 2014)	1945K
	Common System Capital	3225K
	Total Budget	8480K

MAJOR RISKS		Probability (H,M,L)	Impact to Project (H,M,L)
1	L-0 blade inspection	M	H
2			
3			
4			

<u>Define mitigation and / or contingency strategies where Probability or Impact are High:</u>

1- Inspection and early detection will assist in mitigating major blade failure and allow for planned pocurment of replacement blades.

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AGREED			
Shutdown Manager		Date	
Shutdown Owner		Date	
Executive Owner		Date	

SHUTDOWN CHARTER	
Project Name	2014 Shutdown Charter
Executive Owner	Mark Sidebottom
Shutdown Owner	Debra McLellan
Shutdown Manager	Jason March

Background Information

Based on Shutdown Standardization TMP, and past experience the Point Aconi unit requires a yearly outage for inspection on the boiler pressure parts and refractory repairs. In addition standard TMP's will be completed through the PM database system and any defects determined through the operating year will be addressed if possible.

In 2014 there are a number of Capital projects and inspections which will require the generating units to be shutdown. Some of the capital projects are for life extensions and reliability. The inspections are time stamped, some by the O.E.M. and others by plant operating practices. Both of these are influenced either by Thermal Maintenance Practices or the Life Cycle Management programs of each plant.

A thorough review of previous shutdown inspections, asset health assessments have helped determine the required work.

Shutdown Safety Plan

- Point Aconi is committed to an accident free work place and will be committing to early identification & mitigation any risks to employee safety.
- Safety Stand Down will be coordinated early in the outage schedule, engaging all staff & contractors.
- Safety person will be utilized on outages to assisting in promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, and incident reporting.
- Shutdown Preparation will ensure that equipment and work Areas are properly inspected and safe for use before shutdown begins (Housekeeping, Cranes, Lifting Gear, Lighting, vehicles, etc.)
- Safety Issues and concerns will be discussed with Shutdown leads during planned shutdown meetings.
- All aspects of the safety program will be maintained during the Shutdown.
- All Safety Documentation (Incident Reports, Observation Reports, Etc.) managed by the shutdown safety person will be recorded along with the Shutdown Report for history purposes.
- A pre-return to service walk down inspection and sign-off will be completed prior to hand-off to Operations (Staging, Insulation, Combustibles, and Obstructions).
- Plant Cleanups will be conducted after Shutdowns as required to ensure that the Plant remains Clean & Safe to work in.

Shutdown Objectives	
1	Execute the planned work during the outages safety, on-time and on-budget.
2	Address all known plant issues that affect unit reliability and performance.
3	Completion of planned maintenance and project work during the allocated shutdown schedule.

Role	Responsibilities
Executive Owner	Provides the leadership, priority and commitment to the shutdown scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the shutdown objectives and assuring proper resourcing.
Shutdown Owner	Actively champions and promotes the shutdown work scope. Clarifies Shutdown objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the shutdown manager. Helps remove obstacles to success.
Shutdown Manager	Has overall accountability for the successful execution of the maintenance shutdown in terms of scope, cost, schedule, quality and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other shutdown resources. Continually ensures effective communication with key shutdown stakeholders. Proactively monitors shutdown performance and ensures appropriate action is

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	taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

Unit Outage Overview

A complete review of all known inspections, OEM recommendations and a critical path analysis has identified the following required outage weeks per unit:

For Point Aconi in 2014 the thermal maintenance outage will include:

Unit 1 – Major outage with normal maintenance activities. (6 weeks required)

Major Deliverables	
1	Known required (long lead) parts procured and ETA tracked to delivery.
2	Have all contractor work identified and RFP's / RFQ's drafted for release allowing time for terms and conditions to be finalized. (+$1M)
3	Draft capital list of projects from known work required
4	Validate scope of work with asset experts, asset management group, OEM.
5	Draft more accurate shutdown budget requirements

Assumptions

Economic outages will be assessed as they occur and the ability to reduce scope for the original outage will result on a case by case basis. Opportunities may exist to reduce term labour.

Milestones		Date
1	End of Q1 – Finalized work plan, draft capital list, draft budget	Mar 31st
2	End of Q2 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30th
3	End of Q3 – Finalized budget, capital program and maintenance scope.	Sept. 30th

High Level OM&G Budget		Amount
1	Unit 1 – major turbine maintenance activities	680,000
2	Unit 1 – Boiler inspection and maintenance	2,046,045
3	Unit 1 – Plant Labour & Materials	620,000
	Total Budget	3,346,045

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High Level Capital Budget		Amount
1	Boiler (Economizer Bend, Arrowheads, Loopseal Nozzles,vortex finder)	750,000
2	Boiler Refractory	710,000
3	AVR Replacement	300,000
4	Turbine Control System	1,500,000
5	Turbine Repairs	2,500,000
6	CW Valve Replacement	300,000
	Total Budget	6,060,000

Risks		Probability (H,M,L)	Impact to Project (H,M,L)
1	Boiler (Economizer Bend, Arrowheads, Loopseal Nozzles,vortex finder)	Medium	High
2	Boiler Refractory	Low	High
3	AVR Replacement	Low	High
4	Turbine Control System	Low	Medium
5	Turbine Repairs	High	High
6	CW Valve Replacement	Medium	Medium

- ❑ Start inspecting the boiler as early as possible, the plan is to not work weekends, but will be available if extra boiler repairs are required.
- ❑ AVR is no longer supported by OEM.
- ❑ Turbine Control System is no longer supported by OEM.
- ❑ There are known repairs required on the next scheduled major as per the last shutdown reports from Turbine OEM in 2004 and 2011.
- ❑ CW Valves are original to the plant and are monitored yearly.

Agreed			
Shutdown Manager		**Date**	
Shutdown Owner		**Date**	
Executive Owner		**Date**	

SHUTDOWN CHARTER	
Project Name	2014 Shutdown Charter
Executive Owner	Dave Pickles
Shutdown Owner	Jeff Campbell
Shutdown Manager	Ray Barrett

BACKGROUND INFORMATION

The Charter is based on the Standardized Shutdown TMP. It Identifies our major Shutdown Deliverables for 2014 and provides a high level overview.

In 2014 there are a number of Capital projects and inspections which will require the generating units to be shutdown. Some of the capital projects are for life extensions and reliability. The inspections are time stamped, some by the O.E.M. and others by plant operating practices. Both of these are influenced either by Thermal Maintenance Practices or the Life Cycle Management programs of each plant. This work is also influenced by the Reliability Asset Health assessments.

These Major Items are Identified through review of previous shutdown inspections, asset health assessments, equipment maintenance, operating history, and regulatory time stamped requirements.

SAFETY PLAN

1) Pt. Tupper is committed to an accident free work place and will be committing to early identification & mitigation any risks that pose a threat to employee safety.

2) Safety Stand Down will be coordinated early in the outage schedule, engaging all staff & contractors.

3) Safety person will be utilized on outages to assisting in promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, and incident reporting.

4) Shutdown Preparation will ensure that equipment and work Areas are properly inspected and safe for use before shutdown begins (Housekeeping, Cranes, Lifting Gear, Lighting, vehicles, etc.)

5) Safety Issues and concerns will be discussed with Shutdown leads during planned shutdown meetings.

6) All aspects of the safety program will be maintained during the Shutdown.

7) All Safety Documentation (Incident Reports, Observation Reports, Etc.) managed by the shutdown safety person will be recorded along with the Shutdown Report for history purposes.

8) A pre-return to service walk down inspection and sign-off will be completed prior to hand-off to Operations (Staging, Insulation, Combustibles, and Obstructions).

9) Plant Cleanups will be conducted during and after Shutdowns as required to ensure that the Plant remains Clean & Safe to work in.

SHUTDOWN OBJECTIVES	
1	Accident Free
2	Execute the planned work during the outages safely, on-time and on-budget.
3	At Least 90% Completion Rate of Plant Shutdown Schedule (Projects, Preventative, Issues)
4	Address all known plant issues that affect unit reliability, performance and heat rate.

ROLE	RESPONSIBILITIES
Executive Owner	Provides the leadership, priority and commitment to the shutdown scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the shutdown objectives and assuring proper resourcing.
Shutdown Owner	Actively champions and promotes the shutdown work scope. Clarifies Shutdown objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the shutdown manager. Helps remove obstacles to success.
Shutdown Manager	Has overall accountability for the successful execution of the maintenance shutdown in terms of scope, cost, schedule, and quality and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other shutdown resources. Continually ensures effective communication with key shutdown stakeholders. Proactively monitors shutdown performance and ensures appropriate action is taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

UNIT OUTAGE OVERVIEW

For Pt. Tupper in 2014 the Thermal Maintenance Outage year looks like:

Unit 2 – Major Shutdown (4 Weeks 2nd Q 2014)

- Buner bucket replacement (cap) deferred 2015
  Shut down defects
- # 5 HP heater replacement (cap) deferred 2015
- Boiler Inspection (OM&G)
- Boiler repair (cap) deferred 2015
- CW culvert Cleaning (OM&Gl)
- TSE replacement (Capl) deferred 2015
- Precip inspection(OM&Gl) deferred 2015
- LCM compliance deferred 2015
- TMP compliance deferred 2015
- PM shutdown compliance
- regulatory

MAJOR DELIVERABLES	
1	Draft Scope of Shutdown Capital Projects & Maintenance Inspections / Repairs is developed with time & cost Estimates for Labor Staffing and accurate Budgeting.
2	Validate scope of work with Asset Experts, Asset Management Group, OEMs, Etc.
3	Known required (long lead) materials procured in advance and ETA tracked to delivery.
4	Have all contract work identified and RFP's / RFQ's drafted for release allowing time for terms and conditions to be finalized. (+$1M)

ASSUMPTIONS

Economic outages will be assessed as they occur and the ability to reduce scope for the original outage will result on a case by case basis. Opportunities may exist to reduce term labour.

MILESTONES		Date
1	End of Q1 – Finalized work plan, draft capital list, draft budget	March 31, 2013
2	End of Q2 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2013
3	End of Q3 – Finalized budget, capital program and maintenance scope.	September 30, 2013

HIGH LEVEL OM&G BUDGET		Amount
1	Unit 2 – Major Shutdown (1 Weeks 2nd Q 2014)	0
		250K OM&G
	Total Budget	250K

HIGH LEVEL CAPITAL BUDGET		Amount
	Boiler	
	# 5 heater	
	TSE replacement	
	HPDA replacement	
	Remove 600 V mcc from unit 1	
	Re-heater, super heater	

MAJOR RISKS		Probability (H,M,L)	Impact to Project (H,M,L)
Define mitigation and / or contingency strategies where Probability or Impact are High:			

AGREED			
Shutdown Manager	Raymond Barrett	**Date**	May 2013
Shutdown Owner		**Date**	
Executive Owner		**Date**	

SHUTDOWN CHARTER	
Project Name	2014 Shutdown Charter
Executive Owner	Dave Pickles
Shutdown Owner	Stewart Whynott
Shutdown Manager	Dion Antle

BACKGROUND INFORMATION

The Charter is based on the Standardized Shutdown TMP. It Identifies our major Shutdown Deliverables for 2014 and provides a high level overview.

In 2014 there are a number of Capital projects and inspections which will require the generating units to be shutdown. Some of the capital projects are for life extensions and reliability. The inspections are time stamped, some by the O.E.M. and others by plant operating practices. Both of these are influenced either by Thermal Maintenance Practices or the Life Cycle Management programs of each plant. This work is also influenced by the Reliability Asset Health assessments.

These Major Items are Identified through review of previous shutdown inspections, asset health assessments, equipment maintenance, operating history, and regulatory time stamped requirements.

SAFETY PLAN

1) TRE is committed to an accident free work place and will be committing to early identification & mitigation of any risks that pose a threat to employee safety.

2) Safety Stand Downs will be coordinated early in the outage schedule, engaging all staff & contractors.

3) Safety persons will be utilized on outages to assist promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, and incident reporting.

4) Shutdown Preparation will ensure that equipment and work Areas are properly inspected and safe for use before shutdown begins (Housekeeping, Cranes, Lifting Gear, Lighting, vehicles, etc.)

5) Safety Issues and concerns will be discussed with Shutdown leads during planned shutdown meetings.

6) All aspects of the safety program will be maintained during the Shutdown.

7) All Safety Documentation (Incident Reports, Observation Reports, etc.) managed by the shutdown safety person will be recorded for history purposes.

8) A pre-return to service walk down inspection and sign-off will be completed prior to hand-off to Operations (Staging, Insulation, Combustibles, and Obstructions).

9) Housekeeping standards will be maintained throughout the outage.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

SHUTDOWN OBJECTIVES	
1	Accident Free
2	Execute the planned work during the outages safely, on-time and on-budget.
3	At Least 85% Completion Rate of Plant Shutdown Schedule (Projects, Preventative, Issues)

ROLE	RESPONSIBILITIES
Executive Owner	Provides the leadership, priority and commitment to the shutdown scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the shutdown objectives and assuring proper resourcing.
Shutdown Owner	Actively champions and promotes the shutdown work scope. Clarifies Shutdown objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the shutdown manager. Helps remove obstacles to success.
Shutdown Manager	Has overall accountability for the successful execution of the maintenance shutdown in terms of scope, cost, schedule, quality, and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other shutdown resources. Continually ensures effective communication with key shutdown stakeholders. Proactively monitors shutdown performance and ensures appropriate action is taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

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Shutdown Charter

UNIT OUTAGE OVERVIEW

For TRE in 2014 the Thermal Maintenance Outage year looks like:

Unit 5 – Minor Shutdown (6 Weeks)

- Pantlegs repair
- 5-1 Air Heater Outlet Exp Joint Replacement
- Coal MCC Transformer Replacement
- Precip Refurbishment
- Analytical Panel
- Lube Oil Cooler Retube
- Low Load Valve Replacement
- Boiler Refurbishment
- 5-3 Pulverizer Refurbishments
- 4kV Breakers (2014)
- Resin Replacement 2014
- Safety Valves (OMG)
- Cleaning (Condenser, Precip, Air Heater) (OMG)
- Boiler Maintenance (OMG)
- A1 / A2 Shaker House Fire Line replacement
- ID Fan Beck Drives
- Blowdown Tank Header

Unit 6 – Mini Shutdown (3 weeks)

- TRE6 High Energy Piping Snubbers
- Safety Valves (OMG)
- FAC Inspections (OMG)
- Cleaning (Condenser, Precip, Air Heater) (OMG)

MAJOR DELIVERABLES

1	Draft Scope of Shutdown Capital Projects & Maintenance Inspections / Repairs is developed with time & cost Estimates for Labor Staffing and accurate Budgeting.
2	Validate scope of work with Asset Experts, Asset Management Group, OEMs, Etc.
3	Known required (long lead) materials procured in advance and ETA tracked to delivery.
4	Have all contract work identified and RFP's / RFQ's drafted for release allowing time for terms and conditions to be finalized. (+$1M)

ASSUMPTIONS

Economic outages will be assessed as they occur and the ability to reduce scope for the original outage will result on a case by case basis. Opportunities may exist to reduce term labour.

MILESTONES		Date
1	Finalize work plan (scope freeze), capital list, budget	Outage Start – 30 days

2	Finalize accurate work scope (labour plan).	Outage Start – 30 days

HIGH LEVEL OM&G BUDGET		Amount
1	Unit 5 – Minor Shutdown (6 Weeks)	$750k
2	Unit 6 – Mini Shutdown (3 Weeks)	$750k
	Total Budget	$1.5M

HIGH LEVEL CAPITAL BUDGET		Amount
1	Unit 5 – Minor Shutdown (6 Weeks)	$1.45M
2	Unit 6 – Mini Shutdown (3 Weeks)	$150k
	Total Budget	$1.5M

MAJOR RISKS		Probability (H,M,L)	Impact to Project (H,M,L)
1	All Units – Major Issues found while performing Inspections on Critical Equipment	Low	High
2	Outage planning – resource requirements to properly plan and support the work.	High	High
3	Risk tolerance vs Funding approval	Med	Med

Define mitigation and / or contingency strategies where Probability or Impact are High:

3) Coordinate inspections early in shutdown schedule. Review previous inspections and reliability data.

AGREED			
Shutdown Manager		**Date**	
Shutdown Owner		**Date**	
Executive Owner		**Date**	

SHUTDOWN CHARTER	
Project Name	2014 Shutdown Charter
Executive Owner	Tony Stevens
Shutdown Owner	Tim Gillis
Shutdown Manager	Tim Gillis

BACKGROUND INFORMATION

The Charter is based on the Standardized Shutdown Quality Process. It Identifies our major Shutdown Deliverables for 2014 and provides a high level overview.

In 2014 there are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be shutdown. The inspections and projects can be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs.

These high level Items are Identified thorough review of previous shutdown inspections, asset health assessments, Equipment Maintenance & Operating History, And Regulatory Time Stamped Requirements.

SAFETY PLAN

1) Tufts Cove is committed to an accident free work place and will be committing to early identification & mitigation any risks that pose a threat to employee safety

2) Safety Stand Down will be coordinated early in the outage schedule, engaging all staff & contractors.

3) Safety person will be utilized on outages to assisting in promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, incident reporting, and first aid attendant.

4) Shutdown Preparation will ensure that equipment and work Areas are properly inspected and safe for use before shutdown begins (Cranes, Lifting Gear, Lighting, vehicles, ect.)

5) Safety Issues and concerns will be discussed with Shutdown leads during planned shutdown meetings.

6) All aspects of the safety program will be maintained during the Shutdown.

7) All Safety Documentation (Inc. Reports, Observation Reports, Risk Assessments Ect) managed by the Shutdown Safety Person will be Recorded & Filed along with the Shutdown Report for History & Learning Purposes.

8) Plant Cleanups will be conducted either before or after Shutdowns as required to ensure that the Plant remains Clean & Safe to work in. The Safety person will monitor work sites for congestion and cleanliness and mitigate any issues.

9) Site Emergency Response personnel will be updated by the safety person as to what confined space high angle, and other hazardous work is commencing and advise supervisors to staff ERT members as required.

SHUTDOWN OBJECTIVES	
1	No Accidents
2	Execute the planned work during the outages safety, on-time and on-budget.
3	At Least 90% Completion Rate of Plant Shutdown Schedule (Projects, Preventative, Issues)
4	Address all known plant issues that affect unit reliability and performance.

ROLE	RESPONSIBILITIES
Executive Owner	Promotes Health & Safety Provides the leadership, priority and commitment to the shutdown scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the shutdown objectives and assuring proper resourcing.
Shutdown Owner	Promotes Health & Safety Actively champions and promotes the shutdown work scope. Clarifies Shutdown objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the shutdown manager. Helps remove obstacles to success.
Shutdown Manager	Promotes Health & Safety Has overall accountability for the successful execution of the maintenance shutdown in terms of scope, cost, schedule, and quality and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other shutdown resources. Continually ensures effective communication with key shutdown stakeholders. Proactively monitors shutdown performance and ensures appropriate action is taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

UNIT OUTAGE OVERVIEW

For Tuft's Cove in 2014 the Thermal Maintenance Outage year looks like:

Unit 1 – Major Shutdown (10 Weeks March 2014 - Subject to change with Pending Capital Submission)

- Routine Inspections/Assessments, Preventative Maintenance and Repairs
- Main Feed water Valve Overhauls
- Overhaul & AVK of Boiler Pressure Safety Valves
- Continue Feedwater FAC & High Energy Piping Program
- Coolers Assessments & Possible Upgrades
- Closed Cooling System Piping & Exchangers Replacements / Upgrades
- Inspection of Bled Steam Non-Return Valves
- Turbine Major:
    - HP/IP Turbine 50K Inspections as per TMP-037
    - LP Turbine Inspections as per TMP-037
    - Valves & Chests Inspections
    - Turbine Bolting Replacements (Capital)
    - Possible Stop Valve or Seat Replacements (Capital)
    - HP Inlet Seal Replacements (Capital)
    - Steam Path Audit & Possible Seal Upgrades (Capital)
    - Contingency (IP Row 1C Diaphragm, IP Blading, HP Row4, ect.)
    - LP Erosion Shield Replacements (Capital)
    - Turbine HP/IP Inlets/Loops Piping, Traps, Attachments & Welds (Pending CAP)
    - LH & RH Governor Valve Seats/Strainers Replacement (Capital)
- Motor Refurbishments 4160v (Capital)
- Air Heater Structural Repairs
- DCS Upgrades (Capital)
- Breaker / Switchgear Replacements (Capital)
- Air Receiver Replacements (TBD)

Unit 2 – Minor Shutdown (3 Weeks May 2014 - Subject to change with Pending Capital Submission)

- Routine Inspections/Assessments, Preventative Maintenance and Repairs
- Main Feed water Valve Overhauls
- AVK Only of Boiler Pressure Safety Valves
- Continue Feedwater FAC & High Energy Piping
- Inspection of Bled Steam Non-Return Valves
- Turbine Routine Inspections & Repairs Only
- 20% Eddy Current Testing (Up to 80% for 2014)
- Lube Oil Tank Cleaning & Inspection (Last Done 2008)
- Motor Refurbishments 4160v (Capital)
- Re-Inspection of Erosion Shields on Row6 Blades from Inside Hot well
- DCS Upgrades (Capital)
- Natural Gas Igniters & Valves Upgrades (Capital)
- High Cycle Valve Change Outs (Routines)
- Replace Polisher Valves (Routines)
- Change out Polisher Control Panels (Capital)
- Unit 2 or 3 Vacuum Pump Replacements (Capital)
- Breaker / Switchgear Replacements (Capital)

Unit 3 – Minor Shutdown (3 Weeks October 2014 - Subject to change with Pending Capital Submission)

- Routine Inspections/Assessments, Preventative Maintenance and Repairs
- Replacement of North Drum Safety Valve (Pending Condition)
- Overhaul & AVK of Boiler Pressure Safety Valves
- Main Feed water Valve Overhauls
- Continue Feedwater FAC & High Energy Piping
- Re-Inspection of New Stub Keys on Row 21 Blades from Inside Hot well
- Inspection of Bled Steam Non-Return Valves
- Turbine Routine Inspections & Repairs Only
- Assessment of Condenser Air Extraction Zone Corrosion Rate
- Possible Turbine Lube Oil Purification Upgrade
- West or East Condensate Ext. Pump Replacement/Refurb (Pending CAP)
- Possible Air Heater / Preheater Adjustments
- Motor Refurbishments 4160v (Capital)
- DCS Upgrades (Capital)
- Natural Gas Igniters & Valves Upgrades (Capital)
- High Cycle Valve Change Outs (Routines)
- Replace Polisher Valves (Routines)
- Change out Polisher Control Panels (Capital)
- Hydrogen Panel Replacement (Capital)
- Condenser Tube Replacements (Capital)
- Breaker / Switchgear Replacements (Capital)

MAJOR DELIVERABLES	
1	Known required (long lead) materials procured in advance and ETA tracked to delivery.
2	Have all contract work identified and RFP's / RFQ's (Unit 1 Turbine Major) drafted for release allowing time for terms and conditions to be finalized. (+$1M)
3	Draft Scope of Shutdown Capital Projects & Maintenance Inspections / Repairs is developed with time & cost Estimates for Labor Staffing and accurate Budgeting.
4	Validate scope of work with Asset Experts, Asset Management Group, OEMs, Ect.
5	Draft more accurate shutdown budget requirements.

ASSUMPTIONS

Economic outages will be assessed as they occur and the ability to reduce scope for the original outage will result on a case by case basis. As there is only one major turbine Inspection scheduled for 2014 (Unit1), there is a possibility for call backs in advance of one week notice and the ability to further take advantage of economic outages as they occur. Although in taking economic outages or call backs may reduce the completion percentage of the shutdown and some jobs may be cut from the scope. Opportunities may exist to reduce term labor and to focus plant maintenance staff on Capital work.

<u>NOTE 1:</u> Although a 3 week outage period is expected for units 2 & 3, these timelines may grow by 1-2 weeks with the possibility of larger capital projects being approved and driving the outage length.

<u>NOTE2:</u> Unit1 is scheduled off for a IP/LP Inspection in 2014 and a HP Inspection in 2016 based on hours. There is a good chance based the TGA assessment and the guidance of the Asset management office that the HP Inspection will be brought forward to 2014. This charter reflects the possibility that unit1 HP Turbine major will be completed in conjunction with the IP/LP Inspections in 2014.

<u>NOTE3:</u> Unit1 Air heater & Unit3 Condenser will require significant capital investment in the coming years to improve efficiency and integrity, this possible investment is captured in the 5 year plan but omitted in this charter pending engineering assessment for economics & viability.

MILESTONES		Date
1	End of Q1 – Finalized work plan, draft capital list, draft budget	March 31, 2013
2	End of Q2 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2013
3	End of Q3 – Finalized budget, capital program and maintenance scope.	September 30, 2013

HIGH LEVEL OM&G BUDGET		Amount
1	Unit 1 – Major Shutdown (10 Weeks March 2014)	1,950,000
2	Unit 2 – Minor Shutdown (3 Weeks May 2014)	880,000
3	Unit 3 – Minor Shutdown (3 Weeks October 2014)	750,000
	Total Budget	3,200,000

HIGH LEVEL CAPITAL BUDGET		Amount
1	Unit 1 – Major Shutdown (10 Weeks March 2014)	3.400,000
2	Unit 2 – Minor Shutdown (3 Weeks May 2014)	830,000
3	Unit 3 – Minor Shutdown (3 Weeks October 2014)	1,080,000
	Total Budget	5,310,000

MAJOR RISKS		Probability (H,M,L)	Impact to Project (H,M,L)
1	**Unit 1 -** Turbine Inspection Contingencies are not in place, a major turbine capital replacement is not identified and budgeted prior to outage, Turbine inspections reveals unforeseen and unplanned costs	Med	High
2	**All Units -** Financial, Capital, Planning & Procurement Deadlines are not met in a timely manner.	Low	Med
3	**All Units** – Large amount of Capital and Major Shutdown Work/Assessments from 2013 Carry Over to Effect Scope and deadlines for 2014.	Low	Med

Define mitigation and / or contingency strategies where Probability or Impact are High:

Unit 1 - Turbine Inspection Contingencies are not in place, a major turbine capital replacement is not identified and budgeted prior to outage, Turbine inspections reveals unforeseen and unplanned costs.

Unidentified and unforeseen costs can be mitigated by reviewing TGA documentation, reviewing past history and consulting with the Asset Management Office subject matter experts to set up effective contingency plans for both suspect and unknown issues that may be encountered during the turbine inspections. These may include but are not limited to, setting up suppliers, manufactures and service providers for quick turnarounds to mitigate logistic & procurement problems. Consulting with OEM or aftermarket suppliers to discuss options for long lead items, and adding the appropriate contingencies based on history to our budgets, and exploring various repair options for large items prior to shutdown.

AGREED			
Shutdown Manager		**Date**	
Shutdown Owner		**Date**	
Executive Owner		**Date**	

OUTAGE CHARTER	
Project Name	2015 Outage Charter
Executive Owner	Dave Pickles
Outage Owner	Jamie MacDonald
Outage Manager	Jerry Bedecki

BACKGROUND INFORMATION

The Charter is based on the Standardized Outage Quality Process. It Identifies our major Outage Deliverables for 2015 and provides a high level overview.

In 2015 there are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be in an Outage. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs.

These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, and Regulatory Time Stamped Requirements.

SAFETY PLAN

1) The Lingan Generating Station is committed to an accident-free workplace and will be committing to early identification and mitigation of any risks that pose a threat to employee safety.
2) A Safety Stand Down will be coordinated early in the outage schedule, engaging all staff & contractors.
3) A Safety Officer will be utilized on outages to assisting in promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, incident reporting, and first aid attendant.
4) Outage Preparation will ensure that equipment and work Areas are properly inspected and safe for use before Outage begins (Cranes, Lifting Gear, Lighting, vehicles, etc.)
5) Safety Issues and concerns will be discussed with Package Owners and Leads during regular Outage meetings.
6) All aspects of NSPI's Safety Program will be maintained during the Outage.
7) All Safety Documentation (Incident Reports, Observation Reports, Risk Assessments, etc.) managed by the Safety Officer will be Recorded & Filed along with the Outage Report for History and Lessons Learned Purposes.
8) Plant Clean-ups will be conducted before, during and after Outages as required to ensure that the Plant remains Clean and Safe to work in. The Safety Officer will monitor work sites for congestion and cleanliness and mitigate any issues.
9) Site Emergency Response personnel will be updated by the Safety Officer as to what confined space, high angle, and other hazardous work is commencing and advise supervisors to staff ERT members as required.

OUTAGE OBJECTIVES	
1	No Lost time or Medical Aid Incidents.
2	Execute the planned work during the outages safely, on time and on budget.
3	At least 90% completion of identified Plant Outage scope (project work, PMs, defects, etc.)
4	Address all known plant issues that affect unit reliability and performance.
5	Document the outage to support both internal, and external auditing processes.

ROLE	RESPONSIBILITIES
Executive Owner	Promotes Health & Safety Provides the leadership, priority and commitment to the Outage scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the Outage objectives and assuring proper resourcing.
Outage Owner	Promotes Health & Safety Actively champions and promotes the Outage work scope. Clarifies Outage objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the Outage manager. Helps remove obstacles to success.
Outage Manager	Promotes Health & Safety Has overall accountability for the successful execution of the maintenance Outage in terms of scope, cost, schedule, and quality and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other Outage resources. Continually ensures effective communication with key Outage stakeholders. Proactively monitors Outage performance and ensures appropriate action is taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

UNIT OUTAGE OVERVIEW

Unit 1

General:
Minor Outage, 3 Weeks

Capital:
Boiler refurbishment
BFP Prop valve installation
Load load lines and valves

Operating:
NERC PMs – relays and UPS
HEP/FAC inspections
Turbine LP Last Stage Blade inspection (contingency plan required)
Main stop valve and governer valve inspection (contingency plan required)

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Unit 2

General:
Minor Outage, 3 Weeks

Capital:
Burner Front Replacement
Boiler Refurbishment

Operating:
NERC PMs – relays and UPS
HEP/FAC inspections
Turbine LP Last Stage BladeLH & RH inspection (contingency plan required)

***

Unit 3

General:
Major Outage, 9 Weeks (chemical clean is the driver for 9 weeks)

Capital:
Turbine Major (some contingency planning required)
- L-0 Blade Replacement
- Valve Overhaul
- LP gland refurbishment
- Mechanical governmor refurbishment

Generator rotor re-wind
Boiler division wall
Boiler chemical cleaning
Condenser Large Bore piping and valves
AVR Replacement
Turbine Fastener Replacement
HVB Replacement
DAS Replacement
Boiler Refurbishment
CC Blade Replacement, Rows 8, 9, 10
SCC Replacement
Air Heater baskets and Seals
Burner Front Replacements
Chemical Sampling Panel
ICV Ring Replacement

Operating:
NERC PMs – relays and UPS
HEP/FAC inspections
Turbine LP Last Stage LH & RH Blade replacement(contingency plan required
Possible generator stator re-wedge (contingency plan required)

NOTE: Under discussion, consider moving boiler work to Unit 4 for 2015 which relieves some pressure on the Unit 3 major in 2015. Spreads the load for Unit 3 major work over 2 years. Same will hold true for Unit 4 whose major is due in 2016. AMO and Power Production management.

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REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Unit 4

General:
Minor Outage, 3 Weeks

Capital:
Boiler Refurbishment

Operating:
NERC PMs – relays and UPS
HEP/FAC inspections
Turbine LP Last Stage Blade LH & RH inspection (contingency plan required)
Main stop valve inspection (contingency plan required)

NOTE: Under discussion, consider moving boiler work to Unit 4 for 2015 which relieves some pressure on the Unit 3 major in 2015. Spreads the load for Unit 3 major work over 2 years. Same will hold true for Unit 4 whose major is due in 2016. AMO and Power Production management.

MAJOR DELIVERABLES	
1	Known required (long lead) materials procured in advance and ETA tracked to delivery.
2	Have all contract work identified and RFP's / RFQ's drafted for release allowing time for terms and conditions to be finalized and Contracts awarded in advance of outage start.
3	Draft Scope of Outage Capital Projects & Maintenance Inspections / Repairs is developed with time & cost estimates for labor and accurate budgeting.
4	Validate scope of work with Asset Experts, Asset Management Group, OEMs, etc.
5	Deliverables as identified through the Outage Standardization process (minutes, Org chart, reports, Work Packages) and thorough recording of risks and change during outage execution.
6	Use of tools developed through the Outage Standardization Process, such as Milestones, during preparation and planning.

ASSUMPTIONS

Economic outages will be assessed as they occur, and the ability to execute scope during this outage and therefore reduce the original defined Outage scope (and therefore term labour requirements etc.) will be evaluated at each opportunity.

	MILESTONES	Date
1	End of Q1, 2014 – Finalized work plan, draft capital list, draft budget	March 31, 2014
2	End of Q2, 2014 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2014
3	End of Q3, 2014 – Finalized budget, capital program and maintenance scope.	September 30, 2014

	HIGH LEVEL OM&G BUDGET	Amount
1	Unit 1 – Minor Outage	515K
2	Unit 2 – Minor Outage	750K
3	Unit 3 – Major Outage	1,805K
4	Unit 4 – Minor Outage)	515K
	Total Budget	3,585K

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

HIGH LEVEL CAPITAL BUDGET (outage scope only)		Amount	Totals
Unit 1	Boiler Refurbishment	$500,000	
	BFP Prop Valve Installation	$237,000	
	Low Load Line and Valves	$26,000	$763,000
Unit 2	Burner Front Replacement	$301,000	
	Boiler Refurbishment	$250,000	$551,000
Unit 3	LIN3 L-0 Blade Replacement	$3,825,903.91	
	LIN3 Rotor Rewind	$2,740,664.90	
	LIN3 Condenser Large Bore Piping and Valves Refurbishment	$1,137,288.05	
	LIN3 AVR Replacement	$818,814.33	
	LIN3 Turbine Fastners Replacement	$779,269.19	
	LIN3 HVB Replacement	$570,532.51	
	LIN3 DAS Replacement	$567,748.41	
	LIN3 Boiler Refurbishment	$500,555.00	
	LIN3 CC BLADE REPL. ROWS 8,9,10	$500,555.00	
	LIN3 SCC Replacement	$500,555.00	
	LIN3 Division Wall	$500,000.00	
	LIN3 Air Heater Baskets and Seals	$500,000.00	
	LIN3 Boiler Chem Clean	$450,000.00	
	LIN3 Gen Stator Rewedge	$400,000.00	
	LIN3 REPLACE BURNER FRONT COMPONENTS	$300,000.00	
	LIN3 Chem Sampling Panel	$250,000.00	
	LIN3 TURBINE VALVES REFURBISHMENT	$161,039.00	
	LIN3 Condenser Plasticor Inserts	$150,000.00	
	LIN3 LP Gland repair	$100,000.00	
	LIN3 Turbine Run Up Modifications (re: two-shift)	$50,000.00	
	LIN3 ICV ring replacement LIN3 LP Gland repair LIN 3 Governor refurbishment	$50,000.00	
	LIN3 Governor refurbishment	$50,000.00	$14,903,000
Unit 4	Boiler Refurbishment	$500,000	$500,000
	Total Budget	$16,717,000	$16,717,000

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

MAJOR RISKS		Probability (H,M,L)	Impact to Project (H,M,L)
1	All Units: All turbine inspection work may result in additional scope. Contingency plans are to be developed for the areas noted above.	Low	High
2	All Units: Late identification of scope may result in unpreparedness for outage (budget item not identified, contract not in place, materials not delivered)	Low	Med

Define mitigation and / or contingency strategies where Probability or Impact are High:

1. Work with AMO personnel and technical experts to ensure appropriate contingency plans are in place.
   Learn from history to help develop and budget for these plans.
2. Using tools such as the Outage Scope Development checklist and Milestones should mitigate the risk of unidentified scope

AGREED			
Outage Manager	G. Bedecki	**Date**	Jun.27, 2014
Outage Owner	Jamie MacDonald	**Date**	July 14, 2014
Executive Owner		**Date**	Sept 4/14

OUTAGE CHARTER	
Project Name	2015 Outage Charter
Executive Owner	Dave Pickles
Outage Owner	Jeff Campbell
Outage Manager	Ray Barrett

BACKGROUND INFORMATION

The Charter is based on the Standardized Outage Quality Process. It Identifies our major Outage Deliverables for 2015 and provides a high level overview.

In 2015 there are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be in an Outage. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs.

These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, and Regulatory Time Stamped Requirements

SAFETY PLAN

1) The Point Tupper Biomass Generating Facility is committed to an accident-free workplace and will be committing to early identification and mitigation of any risks that pose a threat to employee safety.
2) A Safety Stand Down will be coordinated early in the outage schedule, engaging all staff & contractors.
3) A Safety Officer will be utilized on outages to assisting in promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, incident reporting, and first aid attendant.
4) Outage Preparation will ensure that equipment and work Areas are properly inspected and safe for use before Outage begins (Cranes, Lifting Gear, Lighting, vehicles, etc.)
5) Safety Issues and concerns will be discussed with Package Owners and Leads during regular Outage meetings.
6) All aspects of NSPI's Safety Program will be maintained during the Outage.
7) All Safety Documentation (Incident Reports, Observation Reports, Risk Assessments, etc.) managed by the Safety Officer will be Recorded & Filed along with the Outage Report for History and Lessons Learned Purposes.
8) Plant Clean-ups will be conducted before, during and after Outages as required to ensure that the Plant remains Clean and Safe to work in. The Safety Officer will monitor work sites for congestion and cleanliness and mitigate any issues.
9) Site Emergency Response personnel will be updated by the Safety Officer as to what confined space, high angle, and other hazardous work is commencing and advise supervisors to staff ERT members as required.

OUTAGE OBJECTIVES

1	No Lost Time or Medical Aid Incidents
2	Execute the planned work during the outages safely, on time and on budget.
3	At least 90% completion of identified Plant Outage scope (project work, PMs, defects, etc.)
4	Address all known plant issues that affect unit reliability and performance.
5	Document the outage to support both internal, and external auditing processes.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

ROLE	RESPONSIBILITIES
Executive Owner	Promotes Health & Safety Provides the leadership, priority and commitment to the Outage scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the Outage objectives and assuring proper resourcing.
Outage Owner	Promotes Health & Safety Actively champions and promotes the Outage work scope. Clarifies Outage objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the Outage manager. Helps remove obstacles to success.
Outage Manager	Promotes Health & Safety Has overall accountability for the successful execution of the maintenance Outage in terms of scope, cost, schedule, and quality and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other Outage resources. Continually ensures effective communication with key Outage stakeholders. Proactively monitors Outage performance and ensures appropriate action is taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

UNIT OUTAGE OVERVIEW

General:
Minor Outage, 3 weeks (Q2 2015)

Capital:

- PHB - Trancel Screw Annual Refurbishment
- PHB - Boiler Fuel System Refurbishment
- PHB - Ash/Precipitator System Refurbishment
- PHB - ID Fan Inlet Duct Replacement
- PHB - Electromatic Relief Valve Replacement
- PHB - Safety Shower Upgrades
- PHB - Backup Boiler Feed Pump Conversion to Electric
- PHB - Dept 16, Bark Handling Systems
- PHB - Dept 17, Chip Handling Systems
- PHB - A-Frame & Boiler Feeds

Operating:

- CW culvert Inspection/Cleaning
- TMP compliance
- PM Outage compliance
- Fuel system maintenance
- Distributing conveyor
- Bottom ash conveyor
- Superheater inspection
- Ash bunker work
- Safety valve refurbishment
- Boiler inspection, repair

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

MAJOR DELIVERABLES	
1	Known required (long lead) materials procured in advance and ETA tracked to delivery.
2	Have all contract work identified and RFP's / RFQ's drafted for release allowing time for terms and conditions to be finalized and Contracts awarded in advance of outage start.
3	Draft Scope of Outage Capital Projects & Maintenance Inspections / Repairs is developed with time & cost estimates for labor and accurate budgeting.
4	Validate scope of work with Asset Experts, Asset Management Group, OEMs, etc.
5	Deliverables as identified through the Outage Standardization process (minutes, Org chart, reports, Work Packages) and thorough recording of risks and change during outage execution.
6	Use of tools developed through the Outage Standardization Process, such as Milestones, during preparation and planning.

ASSUMPTIONS
Economic outages will be assessed as they occur, and the ability to execute scope during this outage and therefore reduce the original defined Outage scope (and therefore term labour requirements etc.) will be evaluated at each opportunity.

MILESTONES		Date
1	End of Q1, 2014 – Finalized work plan, draft capital list, draft budget	March 31, 2014
2	End of Q2, 2014 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2014
3	End of Q3, 2014 – Finalized budget, capital program and maintenance scope.	September 30, 2014

HIGH LEVEL OM&G BUDGET		Amount
1	Boiler Pressure Parts Inspection and Repair	$100,000
2	Safety Valve Refurbishment	$50,000
3	Boiler Fuel System Refurbishment	$172,000
4	CW System Inspection and Accessibility Modifications	$40,000
5	Shutdown Confined Space Attendants, Scaffolding Support, ERT crew.	$125,000
6	Turbine Generator	$40,000
7	Zone support	$20,000
8	Labour	$230,000
9	Rentals	$37,000
10	Precipitator inspection and repair	$25,000
11	Consumables	$11,000
	Total Budget	$850,000

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	HIGH LEVEL CAPITAL BUDGET	Amount
1	PHB - Boiler Kablitz and Internal Refurbishment	$225,000
2	PHB - Trancel Screw Annual Refurbishment	$134,000
4	PHB - Ash Conveyors System Refurbishment	$100,000
5	PHB - ID Fan Inlet Duct Replacement	$352,132
6	PHB - Dept 16, Bark Handling Systems	$50,000
7	PHB - Dept 17, Chip Handling Systems	$25,000
8	PHB - A-Frame & Boiler Feeds	$50,000
		$961,132

	MAJOR RISKS	Probability (H,M,L)	Impact to Project (H,M,L)
1	All turbine, generator and boiler inspection work may result in additional scope. Contingency plans are to be developed for the areas noted above.	Low	High
2	Late identification of scope may result in unpreparedness for outage (budget item not identified, contract not in place, materials not delivered)	Low	Med

Define mitigation and / or contingency strategies where Probability or Impact are High:

1. Work with AMO personnel and technical experts to ensure appropriate contingency plans are in place.
2. Learn from history to help develop and budget for these plans.
3. Using tools such as the Outage Scope Development checklist and Milestones should mitigate the risk of unidentified scope

AGREED			
Outage Manager	Raymond Barrett	Date	Aug.14, 2014
Outage Owner	Jeff Campbell	Date	Aug.14, 2014
Executive Owner	[signature]	Date	Sept4/14

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

OUTAGE CHARTER	
Project Name	2015 Outage Charter
Executive Owner	Dave Pickles
Outage Owner	Ron MacNeil
Outage Manager	Bill Harris

BACKGROUND INFORMATION

The Charter is based on the Standardized Outage Quality Process. It Identifies our major Outage Deliverables for 2015 and provides a high level overview.

In 2015 there are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be in an Outage. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs.

These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, and Regulatory Time Stamped Requirements.

SAFETY PLAN

1) Point Aconi is committed to an accident-free workplace and will be committing to early identification and mitigation of any risks that pose a threat to employee safety.
2) A Safety Stand Down will be coordinated early in the outage schedule, engaging all staff & contractors.
3) A dedicated Safety Officer will be utilized on outages to assisting in promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, incident reporting, and first aid attendant.
4) Outage Preparation will ensure that equipment and work Areas are properly inspected and safe for use before Outage begins (Cranes, Lifting Gear, Lighting, vehicles, etc.)
5) Safety Issues and concerns will be discussed with Package Owners and Leads during regular Outage meetings.
6) All aspects of NSPI's Safety Program will be maintained during the Outage.
7) All Safety Documentation (Incident Reports, Observation Reports, Risk Assessments, etc.) managed by the Safety Officer will be Recorded & Filed along with the Outage Report for History and Lessons Learned Purposes.
8) Plant Clean-ups will be conducted before, during and after Outages as required to ensure that the Plant remains Clean and Safe to work in. The Safety Officer will monitor work sites for congestion and cleanliness and mitigate any issues.
9) Site Emergency Response personnel will be updated by the Safety Officer as to what confined space, high angle, and other hazardous work is commencing and advise supervisors to staff ERT members as required.

OUTAGE OBJECTIVES

1	No Accidents.
2	Execute the planned work during the outages safely, on time and on budget.
3	At least 90% completion of identified Plant Outage scope (project work, PMs, defects, etc.)
4	Address all known plant issues that affect unit reliability and performance.
5	Document the outage to support both internal, and external auditing processes.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

ROLE	RESPONSIBILITIES
Executive Owner	Promotes Health & Safety Provides the leadership, priority and commitment to the Outage scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the Outage objectives and assuring proper resourcing.
Outage Owner	Promotes Health & Safety Actively champions and promotes the Outage work scope. Clarifies Outage objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the Outage manager. Helps remove obstacles to success.
Outage Manager	Promotes Health & Safety Has overall accountability for the successful execution of the maintenance Outage in terms of scope, cost, schedule, and quality and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other Outage resources. Continually ensures effective communication with key Outage stakeholders. Proactively monitors Outage performance and ensures appropriate action is taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

UNIT OUTAGE OVERVIEW

Unit 1

General:
Minor Outage, 4 weeks

Capital:
Boiler Refractory Replacement
Boiler Refurbishment
UPS Battery Chargers Replacement
Boiler Arrowhead Replacement
Screw Cooler Trough Replacement
Stack Lighting Replacement
Limestone Piping Refurbishment
Valve Component Replacement
Expansion Joint Replacement

Operating:
Boiler Inspection
Boiler Deslag and Cleaning
CW Inspection
Frontwall Ribbon Replacement and Repair
Thermocouple Replacement
Ash Silo PM and Filter Separator Bag Replacement
Bottom Ash Screw Cooler PM's and Screw Overlay
Safety Valve Refurbishment and Inspection
NERC PMs – relays and UPS
HEP/FAC inspections
Turbine LP (subject to change after completion of 2014 outage)

MAJOR DELIVERABLES	
1	Known required (long lead) materials procured in advance and ETA tracked to delivery.
2	Have all contract work identified and RFP's / RFQ's drafted for release allowing time for terms and conditions to be finalized and Contracts awarded in advance of outage start.
3	Draft Scope of Outage Capital Projects & Maintenance Inspections / Repairs is developed with time & cost estimates for labor and accurate budgeting.
4	Validate scope of work with Asset Experts, Asset Management Group, OEMs, etc.
5	Deliverables as identified through the Outage Standardization process (minutes, Org chart, reports, Work Packages) and thorough recording of risks and change during outage execution.
6	Use of tools developed through the Outage Standardization Process, such as Milestones, during preparation and planning.

ASSUMPTIONS
Economic outages will be assessed as they occur, and the ability to execute scope during this outage and therefore reduce the original defined Outage scope (and therefore term labour requirements etc.) will be evaluated at each opportunity.

MILESTONES		Date
1	End of Q1, 2014 – Finalized work plan, draft capital list, draft budget	March 31, 2014
2	End of Q2, 2014 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2014
3	End of Q3, 2014 – Finalized budget, capital program and maintenance scope. May require re-validating after completion of 2014 Outage.	September 30, 2014

HIGH LEVEL OM&G BUDGET		Amount
1	Labour	255,895
2	Other Non-Labour	0
3	Materials	388,740
4	Contracts	705,300
	Total Budget	1,349,935

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	HIGH LEVEL CAPITAL BUDGET (outage scope only)	Amount
1	Boiler Refractory Replacement	$751,000
2	Boiler Refurbishment	$242,000
3	UPS Battery Chargers Replacement	$201,000
4	Boiler Arrowhead Replacement	$195,000
5	Screw Cooler Trough Replacement	$188,000
6	Stack Lighting Replacement	$148,000
7	Limestone Piping Refurbishment	$100,000
8	Valve Component Replacement	$87,000
9	Expansion Joint Replacement	$66,000
	Total Budget	$1,978,000

	MAJOR RISKS	Probability (H,M,L)	Impact to Project (H,M,L)
1	Excessive Wear on Boiler Pressure Parts.	Low	Med
2	All turbine inspection work may result in additional scope. Contingency plans are to be developed for the areas noted above.	Low	High
3	Late identification of scope may result in unpreparedness for outage (budget item not identified, contract not in place, materials not delivered)	Low	Med

<u>Define mitigation and / or contingency strategies where Probability or Impact are High:</u>

1. Start inspecting the boiler as early as possible, the plan is to not work weekend, but will be available if extra boiler repairs are required.
2. Work with AMO personnel and technical experts to ensure appropriate contingency plans are in place.
   Learn from history to help develop and budget for these plans.
3. Using tools such as the Outage Scope Development checklist and Milestones should mitigate the risk of unidentified scope

AGREED			
Outage Manager	Bill Harris	**Date**	July 29, 2014
Outage Owner	Ron MacNeil	**Date**	July 29, 2014
Executive Owner	[signature]	**Date**	Sept 4/14

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

OUTAGE CHARTER	
Project Name	2015 Outage Charter
Executive Owner	Dave Pickles
Outage Owner	Jeff Campbell
Outage Manager	Ray Barrett

BACKGROUND INFORMATION

The Charter is based on the Standardized Outage Quality Process. It Identifies our major Outage Deliverables for 2015 and provides a high level overview.

In 2015 there are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be in an Outage. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs.

These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, and Regulatory Time Stamped Requirements

SAFETY PLAN

1) Point Tupper is committed to an accident-free workplace and will be committing to early identification and mitigation of any risks that pose a threat to employee safety.
2) A Safety Stand Down will be coordinated early in the outage schedule, engaging all staff & contractors.
3) A Safety Officer will be utilized on outages to assisting in promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, incident reporting, and first aid attendant.
4) Outage Preparation will ensure that equipment and work Areas are properly inspected and safe for use before Outage begins (Cranes, Lifting Gear, Lighting, vehicles, etc.)
5) Safety Issues and concerns will be discussed with Package Owners and Leads during regular Outage meetings.
6) All aspects of NSPI's Safety Program will be maintained during the Outage.
7) All Safety Documentation (Incident Reports, Observation Reports, Risk Assessments, etc.) managed by the Safety Officer will be Recorded & Filed along with the Outage Report for History and Lessons Learned Purposes.
8) Plant Clean-ups will be conducted before, during and after Outages as required to ensure that the Plant remains Clean and Safe to work in. The Safety Officer will monitor work sites for congestion and cleanliness and mitigate any issues.
9) Site Emergency Response personnel will be updated by the Safety Officer as to what confined space, high angle, and other hazardous work is commencing and advise supervisors to staff ERT members as required.

OUTAGE OBJECTIVES	
1	No Lost Time or Medical Aid Incidents
2	Execute the planned work during the outages safely, on time and on budget.
3	At least 90% completion of identified Plant Outage scope (project work, PMs, defects, etc.)
4	Address all known plant issues that affect unit reliability and performance.
5	Document the outage to support both internal, and external auditing processes.

ROLE	RESPONSIBILITIES
Executive Owner	Promotes Health & Safety Provides the leadership, priority and commitment to the Outage scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the Outage objectives and assuring proper resourcing.
Outage Owner	Promotes Health & Safety Actively champions and promotes the Outage work scope. Clarifies Outage objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the Outage manager. Helps remove obstacles to success.
Outage Manager	Promotes Health & Safety Has overall accountability for the successful execution of the maintenance Outage in terms of scope, cost, schedule, and quality and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other Outage resources. Continually ensures effective communication with key Outage stakeholders. Proactively monitors Outage performance and ensures appropriate action is taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

UNIT OUTAGE OVERVIEW

Unit 2

General:
Minor Outage, 4 weeks

Capital:
Boiler Refurbishment
#5 HP Heater Replacement
MCC Controls Upgrade
North Steam Coil Replacement
Coal Nozzle &Bucket Replacement
AVR Replacement
O2 analyzers
Turbine steam chest overhaul (governor valve, etc.)
CW Pump rebuild (pending 2014 inspection)
Stack Repairs
Flame Scanner Replacement
DW Cooler Refurbishment/replacement
Condenser level control replacement

South Boiler Feedpump (pending pump performance test, not currently listed in Capital budget)
Partial Rotor Re-wind (see Major Risks section below, not currently listed in Capital budget)

Operating:
HEP/FAC (~$20K anticipated)
NERC – relays/UPS
Turbine LP Last Stage (LH & RH and R21) Blade inspection (contingency plan required)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

MAJOR DELIVERABLES	
1	Known required (long lead) materials procured in advance and ETA tracked to delivery.
2	Have all contract work identified and RFP's / RFQ's drafted for release allowing time for terms and conditions to be finalized and Contracts awarded in advance of outage start.
3	Draft Scope of Outage Capital Projects & Maintenance Inspections / Repairs is developed with time & cost estimates for labor and accurate budgeting.
4	Validate scope of work with Asset Experts, Asset Management Group, OEMs, etc.
5	Deliverables as identified through the Outage Standardization process (minutes, Org chart, reports, Work Packages) and thorough recording of risks and change during outage execution.
6	Use of tools developed through the Outage Standardization Process, such as Milestones, during preparation and planning.

ASSUMPTIONS
Economic outages will be assessed as they occur, and the ability to execute scope during this outage and therefore reduce the original defined Outage scope (and therefore term labour requirements etc.) will be evaluated at each opportunity.

MILESTONES		Date
1	End of Q1, 2014 – Finalized work plan, draft capital list, draft budget	March 31, 2014
2	End of Q2, 2014 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2014
3	End of Q3, 2014 – Finalized budget, capital program and maintenance scope.	September 30, 2014

HIGH LEVEL OM&G BUDGET		Amount
1	Overtime Labour	50K
2	Term Labour	82K
3	Rental	10K
4	Personal Equipment	5K
5	Contracts	311K
6	Material	200K
	Total Budget	658K

HIGH LEVEL CAPITAL BUDGET (outage scope only)		Amount
1	Boiler Refurbishment	$800,000
2	#5 HP Heater Replacement	$800,000
3	MCC Controls Upgrade	$690,000
4	North Steam Coil Replacement	$340.000
5	Coal Nozzle & Bucket Replacement	$340,000
6	AVR Replacement	$300,000
7	Turbine steam chest overhaul (governor valve, etc.)	$250,000
8	CW Pump rebuild (pending 2014 inspection)	$200,000
9	Stack Repairs	$100,000
10	Flame Scanner Replacement	$100,000
11	DW Cooler Refurbishment/replacement	$100,000
12	Condenser level control replacement	$100,000
13	O2 Analyzers	$75,000
		$4,195,000

MAJOR RISKS		Probability (H,M,L)	Impact to Project (H,M,L)
1	All turbine inspection work may result in additional scope. Contingency plans are to be developed for the areas noted above.	Low	High
2	Late identification of scope may result in unpreparedness for outage (budget item not identified, contract not in place, materials not delivered)	Low	Med
3	Generator rotor partial re-wind is being evaluated based on recent experience at TUC3. If deemed necessary, this activity may drive an increase in the outage duration.	Med	High

Define mitigation and / or contingency strategies where Probability or Impact are High:

1. Work with AMO personnel and technical experts to ensure appropriate contingency plans are in place.
2. Learn from history to help develop and budget for these plans.
3. Using tools such as the Outage Scope Development checklist and Milestones should mitigate the risk of unidentified scope

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

AGREED			
Outage Manager	Ray Barrett	Date	June 18, 2014
Outage Owner	Jeff Campbell	Date	July 18, 2014
Executive Owner	[signature]	Date	Sept 4/14

OUTAGE CHARTER	
Project Name	2015 Outage Charter
Executive Owner	Dave Pickles
Outage Owner	Stewart Whynott
Outage Manager	Dion Antle

BACKGROUND INFORMATION

The Charter is based on the Standardized Outage Quality Process. It Identifies our major Outage Deliverables for 2015 and provides a high level overview.

In 2015 there are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be in an Outage. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs.

These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, and Regulatory Time Stamped Requirements.

SAFETY PLAN

1) Trenton is committed to an accident-free workplace and will be committing to early identification and mitigation of any risks that pose a threat to employee safety.
2) A Safety Stand Down will be coordinated early in the outage schedule, engaging all staff & contractors.
3) A Safety Officer will be utilized on outages to assisting in promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, incident reporting, and first aid attendant.
4) Outage Preparation will ensure that equipment and work Areas are properly inspected and safe for use before Outage begins (Cranes, Lifting Gear, Lighting, vehicles, etc.)
5) Safety Issues and concerns will be discussed with Package Owners and Leads during regular Outage meetings.
6) All aspects of NSPI's Safety Program will be maintained during the Outage.
7) All Safety Documentation (Incident Reports, Observation Reports, Risk Assessments, etc.) managed by the Safety Officer will be Recorded & Filed along with the Outage Report for History and Lessons Learned Purposes.
8) Plant Clean-ups will be conducted before, during and after Outages as required to ensure that the Plant remains Clean and Safe to work in. The Safety Officer will monitor work sites for congestion and cleanliness and mitigate any issues.
9) Site Emergency Response personnel will be updated by the Safety Officer as to what confined space, high angle, and other hazardous work is commencing and advise supervisors to staff ERT members as required.

OUTAGE OBJECTIVES

1	No Lost Time or Medical Aid Incidents
2	Execute the planned work during the outages safely, on time and on budget.
3	At least 90% completion of identified Plant Outage scope (project work, PMs, defects, etc.)
4	Address all known plant issues that affect unit reliability and performance.
5	Document the outage to support both internal, and external auditing processes.

ROLE	RESPONSIBILITIES
Executive Owner	Promotes Health & Safety Provides the leadership, priority and commitment to the Outage scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the Outage objectives and assuring proper resourcing.
Outage Owner	Promotes Health & Safety Actively champions and promotes the Outage work scope. Clarifies Outage objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the Outage manager. Helps remove obstacles to success.
Outage Manager	Promotes Health & Safety Has overall accountability for the successful execution of the maintenance Outage in terms of scope, cost, schedule, and quality and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other Outage resources. Continually ensures effective communication with key Outage stakeholders. Proactively monitors Outage performance and ensures appropriate action is taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

UNIT OUTAGE OVERVIEW

Unit 5

General:
Minor Outage, 4 weeks

Capital:
Turbine Valves (main stop valve, control valves)
Baghouse Bag replacements
Air Heater – reinstall Basket Grids and Structural repair
Boiler select tube replacements
Burner refurbishments
Tundish drain replacement
CW Screen refurbishment
Burner Management System replacement (I&E)
5-1 CE Pump refurbishment
Battery bank replacement
Coal Run – Belts, Reclaim Hoppers, F belt and E belt gearbox replacements
Baghouse Bag Replacement

Operating:
NERC PMs – generator protection relays calibrations and battery testing
Motor protection relay calibrations and generator testing (doble testing partial discharge testing, etc.)
Turbine LP LAst Stage Blade inspection (contingency plan required)
Primary Air Heater repairs
Main Feedwater Valve – inspection
HP Heaters valve repairs
ID Fan Discharge Dampers and VIVs
FD & PA Fan VIVs
Various valve repairs
Safety valve rebuild / calibrations
Instrument calibrations
Precipitator inspection and repairs
Main steam valve weld inspection (contingency plan required)
HEP/FAC inspections (note, no funding has been included in the OM&G budget for this work while awaiting development of the plan)

Nova Scotia POWER An Emera Company

Outage Charter

Unit 6

General:
Minor Outage, 6 weeks (pulverizer refurbishment is driver for 6 week duration)

Capital:
Coal Run – Belts, Reclaim Hoppers
6A and 6B Pulverizer refurbishment
Turbine controls power suppliers
Bottom ash seal replacement
Air Heater Refurbishments
Boiler Refurbishment (including bifurcates)
Condenser Waterbox and Piping Reline
FAC / HE Piping Replacements

Operating:
NERC PMs – relays and UPS
Turbine LP Row6 LH & RH Blading inspection (contingency plan required)
Turbine LP Inspection
Precip repairs
High Energy Piping
Air Heater Structure and Baskets inspection
6A Boiler Feed Pump – remove Fluid Coupling (AMO intends to look further into this)
Bottom Ash Seal
Stack Breaching repairs
PA Duct repair
Fan VIVs
Turbine governor valve overhaul (Inspection planned, no capital funding planned at this time)
Turbine main stop valve overhaul (Inspection planned, no capital funding planned at this time)
HEP/FAC inspections (no funding has been included in the OM&G plan for this while awaiting plan development)

MAJOR DELIVERABLES	
1	Known required (long lead) materials procured in advance and ETA tracked to delivery.
2	Have all contract work identified and RFP's / RFQ's drafted for release allowing time for terms and conditions to be finalized and Contracts awarded in advance of outage start.
3	Draft Scope of Outage Capital Projects & Maintenance Inspections / Repairs is developed with time & cost estimates for labor and accurate budgeting.
4	Validate scope of work with Asset Experts, Asset Management Group, OEMs, etc.
5	Deliverables as identified through the Outage Standardization process (minutes, Org chart, reports, Work Packages) and thorough recording of risks and change during outage execution.
6	Use of tools developed through the Outage Standardization Process, such as Milestones, during preparation and planning.

ASSUMPTIONS
Economic outages will be assessed as they occur, and the ability to execute scope during this outage and therefore reduce the original defined Outage scope (and therefore term labour requirements etc.) will be evaluated at each opportunity.

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MILESTONES		Date
1	End of Q1, 2014 – Finalized work plan, draft capital list, draft budget	March 31, 2014
2	End of Q2, 2014 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2014
3	End of Q3, 2014 – Finalized budget, capital program and maintenance scope.	September 30, 2014

Note: Scope and budget details subject to change based on findings during execution of 2014 outages.

HIGH LEVEL OM&G BUDGET		Amount
1	Unit 5 – Minor Outage	$750K
2	Unit 6 – Major Outage	$900K
	Total Budget	$1.65M

HIGH LEVEL CAPITAL BUDGET (outage scope only)		Amount	Totals
Unit 5	Turbine Valves (main stop valve, control valves)	$750,000	
	Boiler refurbishment	$600,000	
	Air Heater – reinstall Basket Grids and Structural repair	$500,000	
	Air heater upgrades	$500,000	
	Coal Run – Belts, Reclaim Hoppers	$500,000	
	Burner refurbishments	$250,000	
	Burner Managmement System replacement (I&E)	$200,000	
	5-1 CE Pump refurbishment	$200,000	
	CW Screen refurbishment	$175,000	
	Battery bank replacement	$150,000	
	Baghouse Bag Replacement	$150,000	
	Tundish drain replacement	$135,000	$4,110,000
Unit 6	Boiler refurbishment (including bifurcates)	$800,000	
	Air Heater Refurbishments	$750,000	
	Pulverizer refurbishment	$650,000	
	Condenser Waterbox and Piping Reline	$425,000	
	Bottom ash seal replacement	$250,000	
	Turbine controls power suppliers	$200,000	
	Coal Run – Belts, Reclaim Hoppers	$150,000	
	FAC HE Piping Replacements	$50,000	$3,275,000
	Total Budget	$7,385,000	$7,385,000

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia POWER
An Emera Company

MAJOR RISKS		Probability (H,M,L)	Impact to Project (H,M,L)
1	All Units: All turbine inspection work may result in additional scope. Contingency plans are to be developed for the areas noted above.	Low	High
2	All Units: Late identification of scope may result in unpreparedness for outage (budget item not identified, contract not in place, materials not delivered)	Low	Med
3	TRE5 and TRE6 HP Feedwater Heaters have been evaluated, and should not require Capital expenditure in 2015. Should conditions change or wear be faster than expected, these may have to be addressed sooner.	Low	High
4	Low Load Valve replacement for TRE5 is planned for 2014. If this does not get executed in 2014, it will have to be completed in 2015 at a capital cost of approximately $200K.	Low	Med

Define mitigation and / or contingency strategies where Probability or Impact are High:

1. Work with AMO personnel and technical experts to ensure appropriate contingency plans are in place.
   For TRE5 main steam valve weld inspection: Contingency must be put in place in case repair is required.
   For TRE6 Turbine LP: Rapid turnaround of inspection analysis will be required, and a repair/part sourcing plan put in place.
   Learn from history to help develop and budget for these plans.

2. Using tools such as the Outage Scope Development checklist and Milestones should mitigate the risk of unidentified scope

AGREED			
Outage Manager	Dion Antle	Date	July 24, 2014
Outage Owner	Stewart Whynott	Date	July 24, 2014
Executive Owner	[signature]	Date	Oct 22/14

OUTAGE CHARTER	
Project Name	2015 Outage Charter
Executive Owner	Dave Pickles
Outage Owner	Tony Stevens
Outage Manager	Tim Gillis

BACKGROUND INFORMATION

The Charter is based on the Standardized Outage Quality Process. It Identifies our major Outage Deliverables for 2015 and provides a high level overview.

In 2015 there are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be in an Outage. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs.

These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, and Regulatory Time Stamped Requirements.

SAFETY PLAN

1) Tufts Cove is committed to an accident-free workplace and will be committing to early identification and mitigation of any risks that pose a threat to employee safety.
2) A Safety Stand Down will be coordinated early in the outage schedule, engaging all staff & contractors.
3) A Safety Officer will be utilized on outages to assisting in promoting safety awareness, job observation, risk assessments, housekeeping, restricted area identification, incident reporting, and first aid attendant.
4) Outage Preparation will ensure that equipment and work Areas are properly inspected and safe for use before Outage begins (Cranes, Lifting Gear, Lighting, vehicles, etc.)
5) Safety Issues and concerns will be discussed with Package Owners and Leads during regular Outage meetings.
6) All aspects of NSPI's Safety Program will be maintained during the Outage.
7) All Safety Documentation (Incident Reports, Observation Reports, Risk Assessments, etc.) managed by the Safety Officer will be Recorded & Filed along with the Outage Report for History and Lessons Learned Purposes.
8) Plant Clean-ups will be conducted before, during and after Outages as required to ensure that the Plant remains Clean and Safe to work in. The Safety Officer will monitor work sites for congestion and cleanliness and mitigate any issues.
9) Site Emergency Response personnel will be updated by the Safety Officer as to what confined space, high angle, and other hazardous work is commencing and advise supervisors to staff ERT members as required.

OUTAGE OBJECTIVES	
1	No Lost Time or Medical Aid Incidents
2	Execute the planned work during the outages safely, on time and on budget.
3	At least 90% completion of identified Plant Outage scope (project work, PMs, defects, etc.)
4	Address all known plant issues that affect unit reliability and performance.
5	Document the outage to support both internal, and external auditing processes.

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ROLE	RESPONSIBILITIES
Executive Owner	Promotes Health & Safety Provides the leadership, priority and commitment to the Outage scope from the senior executive perspective. Serves as liaison to the NSPI Leadership Team, communicating the Outage objectives and assuring proper resourcing.
Outage Owner	Promotes Health & Safety Actively champions and promotes the Outage work scope. Clarifies Outage objectives and deliverables. Assists with the resolution of issues that cannot be resolved by the Outage manager. Helps remove obstacles to success.
Outage Manager	Promotes Health & Safety Has overall accountability for the successful execution of the maintenance Outage in terms of scope, cost, schedule, and quality and customer satisfaction, from initial involvement to completion. Provides ongoing direction, motivation and support to plant staff and other Outage resources. Continually ensures effective communication with key Outage stakeholders. Proactively monitors Outage performance and ensures appropriate action is taken to address risks and issues. Ensures proper documentation is created, maintained and archived.

UNIT OUTAGE OVERVIEW

Unit 1

General:
Minor Outage, 4 weeks (driver, turbine valve refurbishment)

Capital:

- Polisher upgrades ($200K)
- Gas Block Valves ($125K)
- Analytical panel replacement (TUC1 & 2) ($125K, split between two units)
- Turbine Valve Refurbishment ($450K)

Operating:

- Turbine IP/LP and DFLP semi complete Inspection (contingency planning required, pending review of Dispatch, costing included in High Level OM&G Budget below, $100K included for phased array
- Turbine LP Last Stage Blade inspection (contingency plan required) (Pending Review of Dispatch, costing included in High Level OM&G budget below)
- NERC PMs – relays and UPS
- HEP/FAC inspections (~$100K anticipated)
- Routine Annual Inspections/Assessments, Preventative Maintenance & Repairs
- Replacement of North Boiler Feedpump Discharge Check Valve
- Annual Boiler Inspection
- Boiler Gas Leakage Mitigation (Duel Fuel Capability)
- Routine Inspections/Assessments, Preventative Maintenance and Repairs
- Main Feed water Valve Overhauls
- Overhaul & AVK of Boiler Pressure Safety Valves
- Continue Feedwater FAC & High Energy Piping Program
- Coolers Assessments & Possible Upgrades
- Closed Cooling System Piping & Exchangers Replacements / Upgrades
- Inspection of Bled Steam Non-Return Valves

Notes:

- Due to higher than forecasted dispatch, TUC1 turbine inspections and valve refurbishments have been brought into 2015.

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Unit 2

General:
Minor Outage, 4 weeks

Capital:
- Rotary Air Heater refurbishment ($500K)
- Analytical panel replacement (TUC1 & 2) ($125K, split between two units)
- Polisher upgrade ($125K)
- DCS upgrade ($100K)
- North BFP Refurbishment ($191K)

Turbine DFLP blade 75 replacement (one blade, $112K+ install, pending review of Next Scheduled LP Outage and Recommendation from Siemens, not currently in the Capital plan, see Major Risks below)

Operating:
- NERC PMs – relays and UPS
- HEP/FAC inspections & Re-Inspection of Main Steam "Y" Section HEP/FAC inspections (~$100K anticipated)
- Turbine LP Spindle HCF Assessments (cost currently uncertain)
- Lube Oil Tank Cleaning
- Condenser Eddy Current Testing – 20% Survey
- EVT Only of Boiler Pressure Safety Valves
- Inspection of Bled Steam Non-Return Valves

Notes:
- Turbine DFLP & LP Inspections not included in Operating budget (not expected until 2016)
    - Turbine DFLP disk inspection
    - Turbine DFLP axial entry attachment inspection
    - Turbine LP Last Stage Blade inspection

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Unit 3

General:
Minor Outage, 4 weeks

Capital:
- DCS Upgrade
- Chimney Refurbishment
- Turbine Main Steam Chest Overhaul (main stop valve & governor)(contingency plan required):
    - Excavate & Weld Repairs to LH & RH ESV Covers
    - Replacement Bushings, Valve Spindles, Seats, and Hardware will be Required

Operating:
- NERC PMs – relays and UPS
- HEP/FAC inspections HEP/FAC inspections (~$100K anticipated)
- Turbine LP Last Stage Blade inspection (contingency plan required)
- Turbine DFLP axial entry attachment inspection (contingency plan required)
- Turbine LP – Weld Repairs to No.5/6 Gland Boxes
- Turbine LP – Hotwell Support Structure Repairs
- Re-inspection of new Stub Keys on Row 21 Blades from inside hot well
- Turbine LP Spindle HCF Assessments
- Routine Annual Inspections/Assessments, Preventative Maintenance & Repairs
- Annual Boiler Inspection
- Economizer Inlet Header Video probe Inspection
- Full Boiler Steam Drum Internal NDE
- Tube Samples – ECO/PSH/SSH/RH
- Condenser Eddy Current Testing – 100% Survey
- AVK Only of Boiler Safety Valves
- Inspection of Bled Steam Non-Return Valves
- Assessment of Condenser Air Extraction Zone Corrosion Rate

Unit 6

General:
3 Weeks

Capital:
- Steam Cycle Dissolved Oxygen Control – $300K
- Condenser Waterbox Refurbishments - $120K

Operating:
- Routine Annual Inspections/Assessments, Preventative Maintenance & Repairs
- Run GSCW Cooling Water to Vacuum Pump Coolers
- Hotwell & LSB Inspections
- Turbine Control Valves – Open & Inspect. (Recommended by Mitsubishi following commissioning and pprox.. 1 year of standard operation.
- Visual Inspections of Boilers and Tube Sampling if Required
- AVK only of Boiler Safety Valves

MAJOR DELIVERABLES	
1	Known required (long lead) materials procured in advance and ETA tracked to delivery.
2	Have all contract work identified and RFP's / RFQ's drafted for release allowing time for terms and conditions to be finalized and Contracts awarded in advance of outage start.
3	Draft Scope of Outage Capital Projects & Maintenance Inspections / Repairs is developed with time & cost estimates for labor and accurate budgeting.
4	Validate scope of work with Asset Experts, Asset Management Group, OEMs, etc.
5	Deliverables as identified through the Outage Standardization process (minutes, Org chart, reports, Work Packages) and thorough recording of risks and change during outage execution.
6	Use of tools developed through the Outage Standardization Process, such as Milestones, during preparation and planning.

ASSUMPTIONS
Economic outages will be assessed as they occur, and the ability to execute scope during this outage and therefore reduce the original defined Outage scope (and therefore term labour requirements etc.) will be evaluated at each opportunity.

MILESTONES		Date
1	End of Q1, 2014 – Finalized work plan, draft capital list, draft budget	March 31, 2014
2	End of Q2, 2014 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2014
3	End of Q3, 2014 – Finalized budget, capital program and maintenance scope.	September 30, 2014

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HIGH LEVEL OM&G BUDGET		Amount	Totals
Unit 1	Weekly Operating Outage Budget ($150K/wk)	$600,000	
	HEP/FAC	$100,000	
	Boiler Gas Leakage	$100,000	$800,000
Unit 2	Weekly Operating Outage Budget ($115/wk)	$460,000	
	HEP/FAC	$100,000	$560,000
Unit 3	Weekly Operating Outage Budget ($150/wk)	$600,000	
	HEP/FAC	$100,000	$700,000
Unit 6	Weekly Operating Outage Budget ($60/wk)	$180,000	
	IST/Mitsubishi OEM Engineering Support	$40,000	$220,000
	Total Budget	$2,280,000	$2,280,000

HIGH LEVEL CAPITAL BUDGET (outage scope only)		Amount	Totals
Unit 1	Turbine Valve Refurbishment	450,000	
	Gas Block Valves	$200,000	
	Analytical Panel Replacement (split between TUC1 & 2)	$125,000	
	Polisher Upgrade	$125,000	$900,000
Unit 2	Analytical Panel Replacement (split between TUC1 & 2)	$125,000	
	DCS Upgrade	$100,000	
	North BFP Refurbishment	$191,000	
	Polisher Upgrade	$125,000	
	Rotary Air Heater Refurbishment	$500,000	$1,041,000
Unit 3	Turbine Steam Chest Overhaul (valves)	$450,000	
	Chimney Refurbishment	$100,000	
	DCS Upgrade	$100,000	$650,000
Unit 6	Steam Cycle Dissolved Oxygen Control	$300,000	
	Condenser Waterbox Refurbishments	$120,000	$420,000
	Total Budget	$3,011,000	$3,011,000

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MAJOR RISKS		Probability (H,M,L)	Impact to Project (H,M,L)
1	All Units: All turbine inspection work may result in additional scope. Contingency plans are to be developed for the areas noted above.	Low	High
2	All Units: Late identification of scope may result in unpreparedness for outage (budget item not identified, contract not in place, materials not delivered)	Low	Med
3	TUC1 boiler gas leakage mitigation (dual fuel capacity) work may result in greater than budgeted Operating costs, or a Capital project	Med	Med
4	TUC2 Blade #75 replacement may be required. Work is still being evaluated. If required, it is anticipated this work would be considered Capital.	Med	Med
5	TUC3 Row 21 blading replacement decision is awaiting resolution of Siemens RCA Findings. May result in a Capital project or additional Operating costs to support the work.	Low	Med

Define mitigation and / or contingency strategies where Probability or Impact are High:

1. Work with AMO personnel and technical experts to ensure appropriate contingency plans are in place.
   Learn from history to help develop and budget for these plans.
2. Using tools such as the Outage Scope Development checklist and Milestones should mitigate the risk of unidentified scope

AGREED			
Outage Manager	Tim Gillis	Date	July 16, 2014
Outage Owner	Tony Stevens	Date	July 16, 2014
Executive Owner	[signature]	Date	Sept 4/14

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Lingan Generating Station	Unit:	1

Executive Owner:	Jamie MacDonald
Outage Owner:	Tony Stevens
Outage Manager:	Jerry Bedecki

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

QP-@001 Shutdown Standardization
Planned Outage Charter
Asset Management Office

Lingan Generating Station Unit1 – 2016
6/29/2015

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	17-Sep-16	Time:	-	Is a Recall Possible?	No
First Re-Sync	14-Oct-16	Time:	-	Time to Recall (Days / Hours)	-
Commercial Operation	15-Oct-16	Time:	-	Estimated Cost to Recall	-

COMMENTS: (Driver for timeline, Include interaction and impacts on other outages, generation and/or transmission)
Start Date Roughly Based on 2015 TMS.
Week Turbine Minor as per Fleet Maintenance Program
4 Week Condenser Coating installation
No Recall Available- Turbine valve and condenser coating
Balance Runs Required on Run-Up (Pending L-0 Blading Decision)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'l
1	3 Week Minor Outage Maintenance Activities ($175,000 / Week)	$525,000		
2	Flow Assisted Corrosion and High Energy Piping Surveys (PDM)	$150,000		
3	Last Stage Blading LH & RH Inspections from Hotwell. (MPI Included)	Included		
4	Rotary Air Preheater Inspections and Seal Clearances (Heat Rate)	Included		
5	NERC PMs, Relay and UPS (NERC)	Included		
6	Standard Instrumentation Calibrations / Correct any Deficiencies (Heat Rate)	Included		
7	SOFA & Secondary Air Dampers - Ensure Full Stroke Capability (Heat Rate)	Included		
Total		$675,000		

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat's
1	**Turbine Main & Reheat Stop/Control Valve Refurbishments (3-4 Yrs)**	$195,000		
	Inspections and Overhaul - Labour , material, consumables	Included		
	Replica & Hardness Testing Program	Included		
	Replica & Hardness Testing Program	Included		
	Intercept Control Valve External Seal Rings Replacement	$15,000		Yes
	Contingency for Spare CV Valve Seat Replacement (Seat Seal Weld Cracking)		$45,000	Yes
	Contingency for Misc. Weld Repairs if Required		$30,000	
2	**Boiler Refurbishment (5yr Plan)**	$500,000		
3	**Bottom Ash Refurbishment (5yr Plan)**	$300,000		
4	**Condenser Plasticor Treatment (Chem Reliability)**	$200,000		
5	**Cycle Isolations - Valves and Steam Trap Replacements as Required (Heat Rat**	Unknown		
6	**Boiler Repairs Resulting from Air in leakage surveys / SB Seals (Heat Rate)**	Unknown		
Total		$1,210,000	$75,000	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	Mid Q2, 2015 - Decision on L-0 Blades and Order Placed with Selected Vendor. (Pending)	May 15, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Turbine Inspections may result in additional scope. Contingency Plans should be developed for items noted above.	Medium	High

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2	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Medium
3	It is likely that Turbine Major for 2016 could be pushed into 2017 or 2018 to allign with Generator outage (Planned in 2018). Also could be pushed into 2017 due to the large major on Lingan 4 due in 2016. This will require assessment and consultation with industry experts, plant, and AMO.	High	Low
4	Lingan Unit1 has been flagged for re-assessment of the maintenance program due to lower projected dispatch. This could reduce the scope of the outage or push it out due to lower running hours. Investment in last stage blading is in question due to a lower projected dispatch and could be defferred.	High	Low
5	Turbine Valves will be open during outage, with large amounts of employees and contractors in the area. Risk of foreign material being dropped of left in machine.	Low	High
6	During the outage major assets will be out of service for an extended period of time. There is risk of degredation should there be inadequate environmental controls.	Low	High

Define mitigation and / or contingency stratagies where probability or impact are high.	
1	Develop Stratagy or Contingency Plans for areas identified.
2	
3	Review with Plant, AMO and Industry Experts for best path forward
4	Review with Plant, AMO and Industry Experts for best path forward. Decision on L-0 Blading Needed.
5	Plan and Implement FME process utilizing fleet standards and practices. Borescope prior to Re-build.
6	Practice environmental controls referancing fleet layup programs

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$78,800

24 Hours	$152,500
48 Hours	$233,000

Agreement			
Outage Manager	G Bedecchi	Date	June 25/15
Outage Owner	[signature]	Date	June 29/15
Executive Owner	[signature]	Date	July 22/15

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Lingan Generating Station	Unit:	2

Executive Owner:	Jamie MacDonald
Outage Owner:	Tony Stevens
Outage Manager:	Jerry Bedecki

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSPI solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	28-May-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	18-Jun-16	Time:	-	Time to Recall (Days / Hours)	9 Days
Commercial Operation	19-Jun-16	Time:	-	Estimated Cost to Recall	$351,500

COMMENTS: (Driver for timeline, Include interaction and impacts on other outages, generation and/or transmission)
Schedule date based on Outage and Layup after U4 Major
3 Week Turbine Valves Outage as per Fleet Maintenance Program (pending actual run time)
Recall may be Possible, But only if Nessesary. Would Require Unplanned Re-Assembly of Turbine Valves and Carry Risk.
Estimated Cost to Recall based on Lingans "Unit Outage Delay" Labour Costs for 72Hrs. (9 Days / 8 Hrs per Day)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	3 Week Minor Outage Maintenance Activities ($175,000 / Week)	$525,000		
2	Flow Assisted Corrosion and High Energy Piping Surveys (Acuren)	$50,000		
3	Last Stage Blading LH & RH Inspections from Hotwell. (MPI Included)	Included		
4	NERC PMs, Relay and UPS (NERC)	Included		
5	Rotary Air Preheater Inspections and Seal Clearances (Heat Rate)	Included		
6	Standard Instrumentation Calibrations / Correct any Deficiencies (Heat Rate)	Included		
7	SOFA & Secondary Air Dampers - Ensure Full Stroke Capability (Heat Rate)	Included		
Total		$575,000	$0	

Capital Overview and High Level Budget

Item Description	Budget	Contingency Plan	Long Lead Matls

1	**Turbine Main & Reheat Stop/Control Valve Refurbishments (3-4 Yrs)**	$195,000		
	Inspections a[redacted]	Included		
	Replica & Har[redacted]	Included		
	Contingency for Non-Spare Materials (Ex. Seats / MS Bypass)		$40,000	Yes
	Contingency for Weld Repairs (If Req'd)		$20,000	
2	**Boiler Refurbishment**	$250,000		
3	**Cycle Isolations - Valves and Steam Trap Replacements as Required (Heat Ra**	Unknown		
4	**Boiler Repairs Resulting from Air in leakage surveys / SB Seals (Heat Rate)**	Unknown		
Total		$250,000	$60,000	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Due to Relatively lower investment in Lingan 2 there will be further non-intrusive inspection to manage mechanical risk. There is a possiblility that inspection could reveal significant repairs not accounted for in budgeting.	Low	High
2	Lingan Unit2 has been flagged for re-assessment of the maintenance program due to greater than previously projected running hours. This could expand the scope of the outage should major asset inspections be warrented.	Medium	High
3	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low

4	Turbine Valves will be open during outage, with large amounts of employees and contractors in the area. Risk of foreign material being dropped of left in machine.	Low	High
Define mitigation and / or contingency strategies where probability or impact are high:			
1	Consider possible contingency scenarios should issues be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.		
2	Update operating life expectations and running hours and re-assess scope.		
3	Plan and Implement FME process utilizing fleet standards and practices. Borescope prior to Re-build.		

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$68,800
24 Hours	$132,800
48 Hours	$218,700

Agreement

Outage Manager:	[signature]	Date:	June 25/15
Outage Owner:	[signature]	Date:	June 29/15
Executive Owner:		Date:	

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Lingan Generating Station	Unit:	3

Executive Owner:	Jamie MacDonald
Outage Owner:	Tony Stevens
Outage Manager:	Jerry Bedecki

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	15-Oct-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	5-Nov-16	Time:	-	Time to Recall (Days / Hours)	6 Days
Commercial Operation	6-Nov-16	Time:	-	Estimated Cost to Recall	$218,700

COMMENTS: (Driver for timeline, Include interaction and impacts on other outages, generation and/or transmission)
Schedule later in year based on 2015 Major overhaul
3 Week Minor Maintenance Outage
Recall Available. Timing depends on Outage Progress.
Estimated Cost to Recall Based on Lingans "Unit Outage Delay" Labour Costs for 48Hrs. (6 Days / 8 Hrs per Day)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	3 Week Minor Outage Maintenance Activities ($175,000 / Week)	$525,000		
2	Flow Assisted Corrosion and High Energy Piping Surveys (Acuren)	$150,000		
3	Last Stage Blading LH & RH Inspections from Hotwell. (MPI Included)	Included		
4	NERC PMs, Relay and UPS (NERC)	Included		
5	Rotary Air Preheater Inspections and Seal Clearances (Heat Rate)	Included		
6	Standard Instrumentation Calibrations / Correct any Deficiencies (Heat Rate)	Included		
7	SOFA & Secondary Air Dampers - Ensure Full Stroke Capability (Heat Rate)	Included		
Total		$675,000		

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	Boiler Refurbishment	$500,000		

2	Cycle Isolations - Valves and Steam Trap Replacements as Required (Heat Rat	Unknown		
3	Boiler Repairs Resulting from Air in leakage surveys / SB Seals (Heat Rate)	Unknown		
Total		$500,000	$0	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Medium
	Define mitigation and / or contingency strategies where probability or impact are high:		
1			
2			
3			

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$68,800
24 Hours	$132,800
48 Hours	$218,700

Agreement

Outage Manager:	G Redecke	Date:	June 25/15

Outage Owner:	[signature]	Date:	June 29/15
Executive Owner:	[signature]	Date:	Sept 22/15

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Lingan Generating Station	Unit:	4

Executive Owner:	Jamie MacDonald
Outage Owner:	Tony Stevens
Outage Manager:	Jerry Bedecki

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

QP-G001 Shutdown Standardization
Planned Outage Charter
Asset Management Office

Lingan Generating Station Unit4 - 2016
6/30/2015

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	2-Apr-16	Time:	-	Is a Recall Possible?	No
First Re-Sync	3-Jun-16	Time:	-	Time to Recall (Days / Hours)	-
Commercial Operation	4-Jun-16	Time:	-	Estimated Cost to Recall	-

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
Based on U3 2015 SD, Start major later due to history of winter weather impact on execution.
9 Week Turbine-Generator Major as per Fleet Maintenance Program (Inlcuding: LP LSB Replace / Genr Rotor Rewind)
No Recall Available
Balance Runs / Commissioning / Testing Required on Run-Up

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	9 Week Major Outage Maintenance Activities ($175,000 / Week)	$1,575,000		
2	Flow Assisted Corrosion and High Energy Piping Surveys	$150,000		
3	NERC PMs, Relay and UPS	Included		
4	Standard Instrumentation Calibrations / Correct any Deficiencies (Heat Rate)	Included		
5	SOFA & Secondary Air Dampers - Ensure Full Stroke Capability (Heat Rate)	Included		
Total		$1,725,000	$0	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	HP-IP Turbine Major Inspection (8yr 60,000hr - Last Inspection 2008)			
	Plant Labour & Contracts (Open & Close)	Included		

	Visual, MT/PT, Phased Array, Shroud Checks, Tenon UT, Bore Exam (10yr)	$180,000		
	Steam Path Audit & Contingency Seal/Gland Replacements	$60,000	$120,000	Yes
	Replace HPIP Rotating Blades Stages 1 & 2		$1,350,000	Yes
	HP-IP Turbine Replications / Hardness Program (Cylinders, Piping, Chests)	$50,000		
	Contingency for Rotating Stages 3,8,9,10.		$750,000	Yes
	Contingency for 2nd & 8th Stage Diaphragm SPE Repairs (Spare for 8th?)		$150,000	Yes
	Contingency for HP & IP Inlet Seal Rings		$40,000	Yes
	Contingency for Unit Allignment if Required		$50,000	
	Contingency for Bearing Re-Babbiting if Required		$20,000	
	Contingency for Governor Refurbishment if Required		$45,000	Yes
2	**LP Turbine Major Inspection (8yr 60,000hr - Last Inspection 2008)**			
	Replacement of L-0 Rotating Blading (Heavy Erosion in 2008)	$4,160,000		Yes
	Plant Labour & Contracts (Open & Close)	Included		
	Visual, MT/PT, Phased Array, Shroud Checks, Tenon UT, Bore Exam(10yr)	Included		
	Eddy-Current Exam L-1 / L-2 / L-3 Rotating Blade Rows	$35,000		
	Replace L-0 Attatchment Pin (2008 Reccomendation)	Included		
	Contingency for 8th Stage Diaphragm SPE Repairs		$100,000	Yes
	Contingency for Tenon/Shroud Weld Repairs (Wastage, Cracking, Etc.)		$100,000	Yes
	Contingency for L-1 Rotating Blade Replacements or L.S. Repair Option		$1,500,000	Yes
	Contingency for LP Gland Casing Repairs and Gland Packing Replacements		$120,000	Yes
	Contingency for Replacement Expansion Bellows if Req'd		$35,000	Yes
3	**High Temperature Fasteners Replacements (5yr Plan)**	$870,000		
4	**Generator Rotor / Stator Major Inspection (Assessment - Last Insp. 2008)**			
	Rotor Rewind (Copper Dusting and Pole X-Over Concerns), Replacement of Rotor Retaining Rings with 18.18 Material	$1,915,000		Yes
	Plant Labour & Contracts (Open & Close)	Included		
	Visual & Electrical Testing. ELCID, PD, PI, Power Factor, Etc.	$40,000		
	Stator Wedge Tap Testing and Contingency Repairs / Partial Re-Wedge	$20,000	$30,000	
	NDE Testing of Rotor Fan Blades	Included		
	Flux Probe Installation	$50,000		
	Contingency for Stator Full Re-wedge		$200,000	
	Contingency for Stator Rewind or Plant Stator Rewind Kit		$4,000,000	
	Contingency for Replacement H2 Seals or Refurbishment		$15,000	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

5	**High Voltage Bushing Replacement**	$630,000		
6	**AVR Replacement**	$815,000		
7	**Turbine Main & Reheat Stop/Control Valve Refurbishments (3-4 Yrs)**	$195,000		
	Inspections and Overhaul - Labour , material, consumables	Included		
	Replica & Hardness Testing Program	Included		
	Intercept Control Valve External Seal Rings Replacement	$15,000		Yes
	Contingency for Spare CV Valve Seat Replacement (Seat Seal Weld Cracking)		$45,000	Yes
	Contingency for Misc. Weld Repairs if Required		$30,000	
8	**Bently Nevada System 1 Upgrades (2008 Report)**	$200,000		
9	**Boiler Refurbishment (5yr Plan)**	$500,000		
10	**Division Wall Replacement**	$640,000		
11	**SH5 refurbishment**	$490,000		
12	**Burner Front component replacement**	$480,000		
13	**Air Heater Baskest and seal replacement**	$480,000		
14	**Bottom Ash Refurbishment (5yr Plan)**	$475,000		
15	**Replace Lingan 4 Sample Panel (Chem Reliability)**	$280,000		
16	**Cycle Isolations - Valves and Steam Trap Replacements as Required (Heat Rat**	Unknown		
17	**Boiler Repairs Resulting from Air in leakage surveys / SB Seals (Heat Rate)**	Unknown		
Total		$12,580,000	$8,700,000+	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	Q2, 2015 – Decision on L-0 Blades and Order Placed with Selected Vendor	July 30, 2015
4	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015
5	Mid Q4, 2015 – Finalize L-0 / Gen Rewind Scope and Award Contracts	November 15, 2015

Risk Identification

	Risks	Probability	Impact
1	Turbine & Generator Inspections may result in additional scope. Contingency Plans should be developed for items noted above.	High	Medium

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.) Note: Decision is needed for LP Last Stage Blading and forgings procured by Mid Q2 for project to proceed in 2016.	Low	High
3	During the outage major assets will be out of service for an extended period of time. There is risk of degredation should there be inadequate environmental controls. (Example: Turbine / Hotwell, Gen Rotor / Stator Enviro Controls)	Low	High
4	L-0 Blading Replacement and Generator Rotor Rewind is pending review and assessment. These items could become capital projects for the unit depending on how further assessments look.	High	Medium
5	During the outage, major assets will be open with large amounts of employees and contractors in the area. Risk of foreign material being dropped or left in the machines.	Low	High
6	Risk that the turbine / generator major on unit4 could get pushed to 2017 based on running hours.	Low	Low
7	There is a possibility that Turbine control valve refurbishments could be pushed into 2016 Major from 2015 due to a large amount of work on Lingan 3 in 2015	Low	Low

Define mitigation and / or contingency strategies where probability or impact are high?	
1	Develop Stratagy or Contingency Plans for areas Identified.
2	Make decision on LP Last Stage Blading project and begin procurement process at earliest opportunity.
3	Practice environmental controls referencing fleet layup programs
4	Plant, Management, and AMO to assess requirements and lock down scope on major items.
5	Plan and implement FME process utilizing fleet standards and practices. Borescope prior to Re-build.
6	Review unit running hours and feasibility to execute in 2017.
7	

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$78,800
24 Hours	$152,500
48 Hours	$233,000

Agreement			
Outage Manager:	G Bedecki	Date:	June 30, 2015
Outage Owner:	[signature]	Date:	June 30/2015
Executive Owner:	[signature]	Date:	Sept 22/15

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Port Hawkesbury Biomass Generating Station	Unit:	PB3

Executive Owner:	Dave Pickles
Outage Owner:	Jeff Campbell
Outage Manager:	Ray Barret

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance &Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of Identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	9-Apr-16	Time:	0:01	Is a Recall Possible?	Yes
First Re-Sync	30-Apr-16	Time:	17:00	Time to Recall (Days / Hours)	5 Days
Commercial Operation	1-May-16	Time:	8:00	Estimated Cost to Recall	$75,500

COMMENTS: (Driver for timeline, Include interaction and impacts on other outages, generation and/or transmission)
Start Date reflects best possible time for outage at PHB, due to fuel condition and supply.
3 Week Minor Maintenance Outage as per Fleet Maintenance Program
Recall may be Possible. Depends on Outage Progress.
Estimated Cost to Recall Based on Point Tupper "Unit Outage Delay" Labour Costs for 40Hrs. (5 Days / 8 Hrs per Day)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	**3 Week Minor Outage Maintenance Activities ($300,000 / Week)**	$900,000		
2	Boiler Inspections and Repairs	Included		
3	Fuel System Maintenance	Included		
4	Conveyor Maintenance	Included		
5	CW Inspections	Included		
6	Precipitator Inspections	Included		
7	General Preventative Maintenance & Repairs	Included		
Total		$900,000	$0	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	**Boiler Refurbishment**	$250,000		
2	**Trancel Screw Annual Refurbishment**	$140,000		
3	**Conveyors & Handling Systems**	$200,000		
4	**HP Caustic Dosing Upgrades (Chem Reliability)**	$150,000		
Total		$740,000	$0	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2			
3			

	Define mitigation and / or contingency strategies where probability or impact are high
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	
3	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$24,200
24 Hours	$45,000
48 Hours	$88,000

Agreement

Outage Manager:	[signature]	Date:	Mar. 27/15
Outage Owner:	[signature]	Date:	Mar 27/15
Executive Owner:	[signature]	Date:	Apr 1/15

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Point Aconi Generating Station	Unit:	1

Executive Owner:	Dave Pickles
Outage Owner:	Ron MacNeil
Outage Manager:	Bill Harris

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance &Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	10-Sep-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	8-Oct-16	Time:	-	Time to Recall (Days / Hours)	6 Days
Commercial Operation	9-Oct-16	Time:	-	Estimated Cost to Recall	$563,800

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
Start Date Roughly Based on 2016 TMS.
4 Week Minor Maintenance Outage as per Fleet Maintenance Program
Recall may be Possible. Depends on Outage Progress.
Estimated Cost to Recall Based on Point Aconi "Unit Outage Delay" Labour Costs for 48Hrs. (6 Days / 8 Hrs per Day)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	4 Week Minor Outage Maintenance Activities ($350,000 / Week)	$1,400,000		
2	Boiler Deslag & Cleaning	Included		
3	Flow Assisted Corrosion and High Energy Piping Surveys (Acuren)	$100,000		
4	Ash Silo PMs & Filter Bag Change Outs	Included		
5	Bottom Ash Screw Cooler PMs	Included		
6	Safety Valve Inspections and Refurbishments	Included		
7	Turbine Last Stage Blading Inspections from Hotwell	Included		
8	NERC PMs, Relay and UPS (NERC)	Included		
9	Standard Instrumentation Calibrations / Correct any Deficiencies (Heat Rate	Included		
10	HP-IP Turbine Leakage High (8%). Check N2 Packing. Feasible? (Heat Rate)	Unknown		
Total		$1,500,000	$0	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	Boiler Refurbishment	$250,000		
2	Boiler Refractory Replacement	$750,000		
3	Boiler Arrowhead Replacements	$220,000		
4	Screw Cooler Trough Replacement (If carried over from 2015)	$70,000		
5	Stack Lighting Replacements	$165,000		
6	Expansion Joint Replacements	$75,000		
7	Baghouse Bag Replacements (5yr Plan)	$500,000		
8	Main Steam Pipe hanger Refurbishments (5yr Plan)	$100,000		
9	4160V Motor / Breakers Program (5yr Plan)	$200,000		
10	CW Valve Refurbishments (5yr Plan)	$200,000		
11	Tubular APH Section Replacements (Heat Rate - Approx 600 Tubes Plugged)	$250,000		
12	Cycle Isolations - Valves and Steam Trap Replacements as Required (Heat Ra	$95,000		
13	Boiler Repairs Resulting from Air in leakage surveys / SB Seals (Heat Rate)	Unknown		
14	Vortex Finder replacement northside	$275,000		
15	SH3 Boiler tube replacement Phase 2	$484,000		
Total		$3,634,000	$0	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2			
3			

	Define mitigation and / or contingency stratagies where probability or Impact are high:
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	
3	

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$143,300
24 Hours	$283,500
48 Hours	$563,800

Agreement

Outage Manager:	[signature]	Date:	April 27/15
Outage Owner:	[signature]	Date:	Apr 27/15
Executive Owner:	[signature]	Date:	May 6/15

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Point Tupper Generating Station	Unit:	2

Executive Owner:	Dave Pickles
Outage Owner:	Jeff Campbell
Outage Manager:	Ray Barret

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance &Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	30-Jul-16	Time:	-	Is a Recall Possible?	No
First Re-Sync	6-Aug-16	Time:	-	Time to Recall (Days / Hours)	-
Commercial Operation	7-Aug-16	Time:	-	Estimated Cost to Recall	-

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
Start Date Roughly Based on ~~2015 TMS.~~ 2016 TMS D.P.
1 Week Minor Maintenance Outage as per Fleet Maintenance Program
Recall not available, outage length does not allow.

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Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Made
1	1 Week Minor Outage Maintenance Activities ($200,000 / Week)	$200,000		
2	General Maintenance Defects & Preventative Maintenance	Included		
3	Boiler Inspection	Included		
4	Precipitator Inspection	Included		
5	CW System & Culvert Cleaning (Heat Rate)	Included		
6	LCM / TMP / PM / Regulatory Compliance	Included		
7	Flow Assisted Corrosion and High Energy Piping Surveys (Acuren)	Included		
8	Turbine Last Stage Blading Inspections from Hotwell (Contingency Included)	Included	60,000	
9	NERC PMs, Relay and UPS (NERC)	Included		
10	Rotary Air Preheater Inspections and Seal Clearances (Heat Rate)	Included		
11	Standard Instrumentation Calibrations / Correct any Deficiencies (Heat Rate	Included		
12	SOFA & Secondary Air Dampers - Ensure Full Stroke Capability (Heat Rate)	Included		
Total		$200,000	$60,000	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Made
1	Replace E belt and refurbish frames and rollers (5yr Plan Item)	$100,000		
2	Refurbish East & West Polisher Pnuematic Valves (Chem Reliability)	$50,000	NSD	
3	LP Dosing Automation (Chem Reliability)	$120,000		
4	Cycle Isolations - Valves and Steam Trap Replacements as Required (Heat Ra	Unknown		
5	Boiler Repairs Resulting from Air in leakage surveys / SB Seals (Heat Rate)	Unknown		
Total		$270,000	$0	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	2016 Outage timeline and scope could increase due to findings in 2015.	Low	Low
2	Contingency plans for Generator and LP/IP Last Stage Blading for Repairs if Required.	Low	High

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3	POT2 Boiler has been identified for possibly needing a chemical cleaning (Latest Report shows loading in the Clean region above 30 mg/cm2). Further investigation and decision on timing needs to be done. Depending on evaluation this could effect outage length and costs.	Medium	High

	Define mitigation and / or contingency strategies where probability or impact are high:
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
3	Develop contingency plans for items identified.
4	Review Requirements with Asset Specialists and develop plan if required.

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$24,200
24 Hours	$45,000
48 Hours	$88,000

Agreement

Outage Manager:		Date:	Mar. 27/15
Outage Owner:		Date:	Mar 27/15
Executive Owner:		Date:	Apr 1/15

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2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Trenton Generating Station	Unit:	5

Executive Owner:	Dave Pickles
Outage Owner:	Stewart Whynott
Outage Manager:	Dion Antle

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	3-Sep-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	8-Oct-16	Time:	-	Time to Recall (Days / Hours)	6 Days
Commercial Operation	9-Oct-16	Time:	-	Estimated Cost to Recall	$201,900

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
Start Date Roughly Based on ~~2015~~ TMS. 2016 TMS DP
5 Week Minor Maintenance Outage as per Fleet Maintenance Program
Recall may be Possible. Depends on Outage Progress
Estimated Cost to Recall Based on Trenton "Unit Outage Delay" Labour Costs for 48Hrs. (6 Days / 8 Hrs per Day)

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Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	5 Week Minor Outage Maintenance Activities ($250,000 / Week)	$1,250,000		
2	Bottom Ash Conveyor System	Included		
3	Precipitator Inspection and Repairs	Included		
4	Turbine Last Stage Blading Inspections from Hotwell	Included		
5	Rotary Air Preheater Inspections and Seal Clearances (Heat Rate)	Included		
6	Standard Instrumentation Calibrations / Correct any Deficiencies (Heat Rate	Included		
7	SOFA & Secondary Air Dampers - Ensure Full Stroke Capability (Heat Rate)	Included		
8	Analytical Panel / GSCW Piping	Included		
Total		$1,250,000	$0	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	Boiler Refurbishment	$600,000		
2	Flow Assisted Corrosion and High Energy Piping Surveys (Acuren)	$300,000		
3	Install Flowmeters for 5-1 / 5-2 Polishers (Chem Reliability)	$15,000		
4	Cycle Isolations - Valves and Steam Trap Replacements as Required (Heat Ra	Unknown		
5	Boiler Repairs Resulting from Air in leakage surveys / SB Seals (Heat Rate)	Unknown		
6	Install Cascade Drain Thermocouples on FW Heaters 1,2,4,5 and 6 (Heat Rat	$50,000		
7	Possible Vacuum Pump Replacement or Refurbishment (Heat Rate - Pendin	$335,000		Yes
8	Air Heater Cold End Baskets and Support Grids - 4wks	$600,000		Yes
9	Possible Feedwater Heater Replacement - No.5-4 / No.5-5/ No.5-6	$900,000		Yes
10	Coal System Upgrades	$500,000		
11	Burner Refurbishments	$250,000		
12	BAS Replacement	$250,000		
13	5-2/5-4 Pulverizor Refurbishments	$350,000		
14	Water Treatment Plant Resin Replacements	$50,000		
15	Drains Cooler Re-tubing	$100,000		
16	Lube Oil Cooler - Replacement Bundle	$250,000		
17	51 Fan Refurbishment	$500,000		
18	Main Boiler Stop Valve Refurbishment	$250,000		
19	GSCW / Common Water System Upgrades	$100,000		
Total		$5,400,000	$0	

Planning Milestones

Milestone	Date

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2			
3			
	Define mitigation and / or contingency stratagies where probability or impact are high:		
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.		
2			
3			

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$64,700
24 Hours	$124,400
48 Hours	$201,900

Agreement

Outage Manager:	[signature]	**Date:**	MAR 30 2015
Outage Owner:	[signature]	**Date:**	Mar 30/15
Executive Owner:	[signature]	**Date:**	Apr 1/15

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER
An Emera Company

Plant / Location:	Trenton Generating Station	Unit:	6

Executive Owner:	Dave Pickles
Outage Owner:	Stewart Whynott
Outage Manager:	Dion Antle

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage Inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	9-Apr-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	7-May-16	Time:	-	Time to Recall (Days / Hours)	9 Days
Commercial Operation	8-May-16	Time:	-	Estimated Cost to Recall	$373,600

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
Spring outage is ideal for Unit6 due to maintenance that will be required on bottom ash early in the year.
4 Week Minor Maintenance Outage as per Fleet Maintenance Program. 4 weeks Required for Condenser Ball Cleaner.
Recall may be Possible. But only if nessessary. Would Require Unplanned Re-Assesmbly of Turbine Valves and Carry Risk
Estimated Cost to Recall Based on Trenton "Unit Outage Delay" Labour Costs for 72Hrs. (9 Days / 8 Hrs per Day)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	4 Week Minor Outage Maintenance Activities ($300,000 / Week)	$1,200,000		
2	Flow Assisted Corrosion and High Energy Piping Surveys (Acuren)	$100,000		
3	Turbine Last Stage Blading Inspections from Hotwell	Included		
4	NERC PMs, Relay and UPS (NERC)	Included		
5	Standard Instrumentation Calibrations / Correct any Deficiencies (Heat Rat	Included		
Total		$1,300,000	$0	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	Turbine Main Valves (Reheat & STG Due in 2017) - 3wk	$650,000		Yes
2	Boiler Refurbishment	$600,000		
3	Bifurcates	$300,000		
4	Condenser Auto Ball Tube Cleaning System (Heat Rate - Review Req) - 4wk	$700,000		Yes
5	Cycle Isolations - Valves and Steam Trap Replacements as Req'd (Heat Rate	Unknown		
6	Boiler Repairs Resulting from Air in leakage surveys / SB Seals (Heat Rate)	Unknown		
7	Bottom Ash Upgrades (Incl. Chain Replacement)	$500,000		
8	Turbine Controls Power Supplies (Deferred from 2015)	$150,000		
9	Exciter and AVR Replacement (Likely 2017)	$750,000		Yes
10	PE for HVB Replacements (required for 2017)			
11	PA Ductwork	$300,000		
12	BAS Replacements	$250,000		
13	CW Pumps Isolation Valve Replacements	$300,000		Yes
14	ID Fan Damper Drive Upgrades	$250,000		
15	6-4 Feedwater Heater Refurbishment	$150,000		
16	Reheat Attemperator Nozzle Replacement	$150,000		
17	W.W. Coolers Replacement	$300,000		
18	Carbon Filters Replacements	$400,000		
Total		$5,750,000	$0	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2	Risk that unit5 could be placed back-to-back with unit6 in the TMS. It is preferable to separate the two outages as having them back-to-back affects planning and execution effectiveness.	Med	Med
3			

	Define mitigation and / or contingency stratagies where probability or impact are high:
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	Communicate need with TMS planning team and identify in charter.
3	

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$81,200
24 Hours	$157,300
48 Hours	$216,400

Agreement

Outage Manager:	[signature]	Date:	MAR 30 2015
Outage Owner:	[signature]	Date:	MAR 30 / 15
Executive Owner:	[signature]	Date:	Apr 1 / 15

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Tufts Cove Generating Station	Unit:	1

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Tim Gillis

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	12-Mar-16	Time:	-	Is a Recall Possible?	No
First Re-Sync	30-Apr-16	Time:	-	Time to Recall (Days / Hours)	-
Commercial Operation	1-May-15	Time:	-	Estimated Cost to Recall	-

COMMENTS: (Driver for timeline, Include interaction and impacts on other outages, generation and/or transmission)
Start date ideal in spring if weather permits, May have ability to move to fall if run hours on IP-LP Permit.
7 Week Turbine Major Inspection (HP-IP-LP) as per Fleet Maintenance Program
No Recall Available. Turbine Outage.
Scope of Unit1 Outage subject to change in timeline & cost due to changing operational forecasts and utilization.

Operating Overview and High Level Budget				
	Item Description	Budget	Contingency Plan	Long Lead Matls
1	**7 Week Major Outage Maintenance Activities ($110,000 / Week)**	$770,000		
2	**Flow Assisted Corrosion and High Energy Piping Surveys**	$120,000		
3	**Boiler Gas Leakage Mitigation (Re-Inspection and repairs as required)**		30,000	
4	**Condenser Eddy Current Testing (100%) (May Defer due to Low Dispatch)**	$30,000		
5	**Annual Boiler Inspection**	Included		
	Superheater Header Inspection (TMP-007 15-20 Year - New in 1999)	$20,000	10,000	
	Reheater Outlet Header Inspection (TMP-007 15-20 Year - New in 1999)	$20,000	10,000	
	Full MT / UT of Steam Drum.	Included		
6	**Main Feedwater Valve Overhauls**	Included		Yes
7	**Turbine Last Stage Blading Inspections from Hotwell**	Included		
8	**NERC PMs, Relay and UPS**	Included		
9	**Lube / Seal Oil Cooler Refurbishments - Pull Tube Bundle**	Included	50,000	
10	**Pressure Safety Valves Testing, and Re-Cert (All Systems / AVK Only on Boile**	$25,000		
11	**Standard Instrumentation Calibrations / Correct any Deficiencies (Heat Rate)**	Included		
Total		$960,000	$50,000	

Capital Overview and High Level Budget				
	Item Description	Budget	Contingency Plan	Long Lead Matls
1	**HP Turbine Inspection & Refurbishment (Due 2017 - Allign with IP/LP 2016)**	$2,200,000		
	Insulation and Scaffolidng	$90,000		
	Remove & Grit Blast Spindle	$70,000		
	Full Visual & MPI of Rot/Stat Blade Paths, Shrouds, Shaft Radii, Root faces.	$60,000		
	Rotor Boresonics Exam	$45,000		
	Phased Array, NDE and Inspection of Blade Attatchements	$35,000		
	HP Spindle Total Runout check	Included		
	Spindle & Casing Replication & Hardness Testing	Included		
	Full Bearing Run Allignment	Included		
	Cylinder Inspection, Replications, Radii Cracking, Erosion, Distortion, Etc	Included		
	Inspection and Possible Replacement of HP & IP Inlet Seal Rings	Included	$50,000	
	Contingency for HP & IP Inlet Seal Ring Replacements (Deferred from 2008)		$120,000	Yes
	Contingency for HP Spindle Blading and Cylinder Joint Weld Repairs		$30,000	
	Contingency for No.1-2 Bearing Refurbishments		$30,000	
	Contingency for Row 4R Repairs		$140,000	Yes
2	**IP Turbine Inspection & Refurbishment (Deferred from 2015)**	Included		
	Insulation and Scaffolidng	$90,000		
	Remove & Grit Blast Spindle	$70,000		
	Grit Blast & MT IP Diaphrams	Included		
	Full Visual & MPI of Rot/Stat Blade Paths, Shrouds, Shaft Radii, Root faces.	$60,000		
	Rotor Boresonics Exam & Scoop Sample	$65,000		
	Phased Array	$35,000		

	Contingency for Stationary Blading & Diaphragms (1C Row Nozzles)		$140,000	Yes
	Contingency for All IP Rows (Confirm if 2R-9R are original to 1970 Rotor)		$160,000	Yes
3	**DFLP Turbine Inspection & Refurbishment (Deferred from 2015)**	Included		
	Insulation and Scaffolidng	$40,000		
	Remove & Grit Blast Spindle	$70,000		
	Grit Blast & MT IP Diaphrams	Included	$15,000	
	Full Visual & MPI of Rot/Stat Blade Paths, Shaft Radii, Root faces.	$60,000		
	Full NDE Inspection of L-1,L-2,L-3 Trailing Edges and Blade Hardware	Included		
	Photograph "As Found / As Left" Condition of LP Blading Erosion	Included		
	Rotor Boresonics Exam & Scoop Sample	$65,000		
	Phased Array, NDE and Inspection of Blade Attatchements	$35,000		
	Contingency for Misc. Erosion Shield Replacement / Repair if Required		$35,000	Yes
	Contingency for Lacing Wire Replacement / Repairs as Req'd		$20,000	Yes
4	**Turbine Valves - CIESV Seat, Main Governor Valve Spindles, Fasteners**	$150,000		
5	**Turbine Glands, Drains, and Loop Assessments (Pending Review)**		$350,000	
6	**South Boiler Feed Pump Refurbishment**	$250,000		
7	**Contingency for Air Heater Structural Repairs. Repair Gas Outlet Roof.**		$250,000	
8	**CW Keyway Repairs - (Assessment in 2015 and Possible Repairs in 2016)**		$75,000	
9	**CW Piping Repairs - (Asssessment in 2015 and Possible Repairs in 2016)**		$150,000	
10	**TSE / Data Manager Upgrades**	$150,000		
11	**Cyclone Block Valve Replacements**	$100,000		Yes
12	**Cycle Isolations - Valves and Steam Trap Replacements as Required (Heat Ra**	Routine		
13	**Repair No.2 Turbine Gland Leak Off Piping (If not Found in 2015) (Heat Rate)**	Routine		
Total		**$3,740,000**	**$1,565,000**	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2	Last HP Turbine Inspection was in 2008 (6yr - 40,000hr). The IP/LP Turbine has been deferred since 2014 and the HP Turbine inspection is scheduled for 2016. Generator planned interval is scheduled for 2017-2018. Due to the unstable forecast of operation and utilization of this unit, changes to this charter and the major scope are subject to change as risk as operating environments change.	High	Medium

3	Due to low projected dispatch on Unit1, operating and capital expendatures may be minimized and require review by plant and AMO. Items are listed above as contingency but have low probability to be implemented in 2016.	High	Low
4	During the outage major assets will be out of service for an extended period of time (Pending Outage Decision). There is risk of degredation should there be inadequate environmental controls.	Low	High
5	During the outage, major assets will be open (Pending Outage Decision) with large amounts of employees and contractors in the area. Risk of foreign material being dropped or left in the machines.	Low	High
Define mitigation and / or contingency stratagies where probability or impact are high:			
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.		
2	Review running hour projections, history and risks with deferring inspection. Develop contingency plans for executing inspection should running hour projections suddenly change. Review options and concerns between Management, Plant Staff, and Asset Management Office.		
3	Same as "Item No.2"		
4	Practice environmental controls referancing fleet layup programs		
5	Plan and Implement FME process utilizing fleet standards and practices. Borescope prior to Re-build.		

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$30,000
24 Hours	$55,000
48 Hours	$92,500

Agreement

Outage Manager:	Tim Gillis	Date:	April 2, 2015
Outage Owner:	Tony [signature]	Date:	March 31/15
Executive Owner:	[signature]	Date:	Apr 17/15

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Tufts Cove Generating Station	Unit:	2

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Tim Gillis

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	22-Oct-16	Time:	-	Is a Recall Possible?	No
First Re-Sync	19-Nov-16	Time:	-	Time to Recall (Days / Hours)	-
Commercial Operation	20-Nov-16	Time:	-	Estimated Cost to Recall	-

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
Start date ideal in fall due to long lead valve materials. Ideal for contingency should utilization and scope increase or decrease.
4 Week Turbine Minor Maintenance Outage as per Fleet Maintenance Program
No Recall Available. Turbine Outage.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	**4 Week Minor Outage Maintenance Activities ($150,000 / Week)**	$600,000		
3	**Flow Assisted Corrosion and High Energy Piping Surveys (MS "Y" Inspect)**	$80,000		
4	**NERC PMs, Relay and UPS (NERC)**	Included		
5	**40% Condenser Eddy Current Testing**	$25,000		
6	**Boiler Inspection**			
	Annual Inspection and Support Bracket Repairs as Req'd.	$50,000	30,000	
	Superheater Header Inspection (TMP-007 250,000 Hr)	$20,000	10,000	
	Reheat Outlet Header Inspection (TMP-007 250,000 Hr)	$20,000	10,000	
	Ecconomizer Inlet Header Videoprobe & NDE Nozzles (Intertek - New 2008)	$20,000	10,000	
	Full MT / UT of Steam Drum. Overdue.	Included		
	Secondary Superheater Tubing Oxide Scale Survey (Intertek)	Reviewing	20,000	
	Reheater Tubing Oxide Scale Survey (Intertek)	Reviewing	20,000	
12	**Pressure Safety Valves Testing, Replacement and Re-Cert (All Systems)**	$20,000		
13	**Rotary Air Preheater Inspections and Seal Clearances (Heat Rate)**	Included		
14	**Standard Instrumentation Calibrations / Correct any Deficiencies (Heat Rate**	Included		
15	**Investigate Possible Division Plate Leak on FW Heater No.6 (Heat Rate)**	Included	100,000	
Total		$835,000	$200,000	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	**Turbine DFLP Semi-Complete (13,600Hr Row6 & 4 Disc Bores - FSN-13-3484)**			
	Remove / Re-Install Crossover & LP Cover	$350,000		
	Visual and MPI of Spindle Blades, Fasteners, Pockets, Root Fixing Grooves	$25,000		
	Visual and UT Inspection of Erosion Shields	Included		
	Blade 75 Option A - PAUT Inspection (OPG Has Probes to Fit / Half Joint)	$55,000		
	Blade 75 Option B - Replacement of Life Expired Blade		$180,000	Yes
	Row6 Disc (FSN-13-3484) 13.6K Hr EOF Inspection (Steeples have C-Groove)	Included		
	Install LP Center Shaft HCF Monitoring System (Pending Review)	$32,000		
	Inspect Row 6 RH Diaphragm for Impact / Erosion Damage	Included		
	Disc Bore Inspection	$60,000		
	Inspect No.4/5 Glands (Let in 2013) Contingency for Replacements	Included	$40,000	
	Inspect IP Last Stage Blading from Hotwell & Contingency Braze Repairs	Included	$50,000	
2	**Turbine Main & Reheat Control Valve Inspections**			
	Perform Main & Reheat Control Valve Inspections (3-4yr Inspection)	$450,000		
	MPI, Replication, Hardness on Weld Repairs in Valve Bodies and Covers	$25,000		
	Confirm Valve Internal Cracking for growth since 2013 Inspection	Included		
	Refurbish or Order New Main ESV Spindle for Inspection	$35,000		Yes
	Require 2 LH Governor Valve Spindles and Spare Bushings for Inspection	$85,000		Yes
	Replace LH & RH Intercept Control Valve Spindles	$75,000		Yes
	Replace Bushings on Slave ESV Relay Piston	$12,000		Yes

	Replace Main Steam Chest Valve Seat Screws	$3,500		Yes
	Bottle studs & Taps for Governor valve Cover Bolt hole Modification 2013	$3,500		Yes
	Stock 2 Sets of Valve Spindle Castle Nuts	$3,500		Yes
	Inspect & Replace Aux Governor Fulcrum Bracket Pins		$5,000	
	Replacement fasteners as per station bolting program		$25,000	
3	**Rotary Air Heater Refurbishments (Deferred from 2015)**	$450,000		Yes
4	**North Boiler Feed Pump Refurbishment**	$250,000		
5	**Condenser Waterbox Refurbishments (Possible Plasticore Treatement)**	$275,000		
6	**CW Piping Repairs - (Asssessment in 2015 and Possible Repairs in 2016)**		$150,000	
7	**Cycle Isolations - Valves and Steam Trap Replacements as Required (Heat Ra**	Routine		
Total		$2,189,500	$450,000	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015
4	Mid Q2, 2016 - Decision and Plan Devloped for L-0 Blades and GenRotor Work in 2017	May 15, 2016

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2	Decision to be made. DFLP is due in 2016, Generator in 2017 (Rotor Rewind Potential, only rings done in 2009), and turbine major in 2018 (>3000 hrs/yr) or 2020 (<3000 hrs/yr). There is a risk that based on running hours the generator outage could be pulled ahead (Rotor Rewind Materials to be ordered Mid Q2 if that is case). Or that the L-0 Blading replacement could get pushed out to 2018-2020 turbine major. L-0 Blades may need to be removed for disc groove inspections regaurdless of blading change outs. (Pending Review).	Medium	High
3	During the outage major assets will be out of service for an extended period of time (Pending Outage Decision). There is risk of degredation should there be inadequate environmental controls.	Low	High
4	During the outage, major assets will be open (Pending Outage Decision) with large amounts of employees and contractors in the area. Risk of foreign material being dropped or left in the machines.	Low	High

Define mitigation and / or contingency stratagies where probability or impact are high:

1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	Discuss Options with Plant, Asset Management Office and Senior Management. Decide on path forward and develop plan to execute.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

3	Practice environmental controls referancing fleet layup programs
4	Plan and Implement FME process utilizing fleet standards and practices. Borescope prior to Re-build.

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$30,000
24 Hours	$55,000
48 Hours	$92,500

Agreement

Outage Manager:	Tim Gillis	Date:	April 2/15
Outage Owner:	[signature]	Date:	April 1/15
Executive Owner:	[signature]	Date:	Apr 17/15

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Tufts Cove Generating Station	Unit:	3

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Tim Gillis

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	30-Apr-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	28-May-16	Time:	-	Time to Recall (Days / Hours)	5 Days
Commercial Operation	29-May-16	Time:	-	Estimated Cost to Recall	$38,700

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
Start date ideal in spring for LP Turbine Inspection. If not done in 2015, then inspection will need to be done in spring
4 Week Minor Turbine Outage as per Fleet Maintenance Program.
Recall may be Possible. Depends on Outage Progress and Final Scope.
Estimated Cost to Recall Based on Tufts Cove "Unit Outage Delay" Labour Costs for 40Hrs. (5 Days / 8 Hrs per Day)

QP-G001 Shutdown Standardization
Planned Outage Charter
Asset Management Office

Tufts Cove Generating Station Unit3 - 2016
4/1/2015

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	**4 Week Minor Outage Maintenance Activities ($150,000 / Week)**	$600,000		
2	**Flow Assisted Corrosion and High Energy Piping Surveys**	$100,000		
3	**Boiler Inspection**			
	Annual Inspection and Support Bracket Repairs as Req'd.	$50,000	30,000	
	Economizer Inlet Header Videoprobe & NDE Nozzles (Intertek - If not in '15)	$15,000	10,000	
	Superheater Header Inspection (TMP-007 250,000 Hr)	$20,000	10,000	
	Reheat Outlet Header Inspection (TMP-007 250,000 Hr)	$20,000	10,000	
	Economizer Tubing Sample & Analysis (Intertek)	$5,000		
	Primary Superheater Tubing Oxide Scale Survey (Intertek)	Reviewing	20,000	
	Reheater Tubing Oxide Scale Survey (Intertek)	Reviewing	35,000	
	Full MT / UT of Steam Drum. Overdue.	Included		
4	**100% Condenser Eddy Current Testing**	$40,000		
5	**NERC PMs, Relay and UPS**	Included		
6	**Pressure Safety Valves Testing, Replacement and Re-Cert (All Systems)**	$20,000		
7	**Rotary Air Preheater Inspections and Seal Clearances (Heat Rate)**	Included		
8	**Standard Instrumentation Calibrations / Correct any Deficiencies (Heat Rate)**	Included		
9	**Replace Turbine Gland Steam Pressure Gauges 3,4,5,6 (Heat Rate)**	Included		
Total		$850,000	$115,000	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	**Turbine DFLP Semi-Complete (15,000Hr E.O.F. LP Half Joint Inspection)**			
	Remove / Re-Install Crossover & LP Cover	$350,000		
	Visual and MPI of Spindle Blades, Fasteners, Pockets, Root Fixing Grooves	$25,000		
	MPI LH & RH Last Stage Blading / Disc End of Face (Solid Shaft with Discs)	Included		
	Visual and UT Inspection of Erosion Shields	Included		
	Possible Repairs to No.5 & 6 Gland Boxes (Fits in Poor Condition in 2012)		$40,000	
	LP/Generator End Hotwell Support Repairs (IP End Repaired Only in 2014)	Included		
3	**LP Rotor Disc Stress Corrosion Life Assessment PB1-08-9002-ST-EN-0**	$35,000		
4	**LP Center Shaft HCF Assessment**	$35,000		
5	**Rotary Air Heater Refurbishments (Assess Requirement in 2015)**	$450,000		Yes
6	**Lube Oil Purifier Upgrade**	$450,000		Yes
7	**North Drum Pressure Safety Valve Replacement (Requires 2015 Assessment)**	$100,000		Yes
8	**Natural Gas Ignitor Upgrades (5yr Plan)**	$200,000		Yes
9	**Hydrogen Panel Upgrades**	$200,000		Yes
10	**CW Piping Refurbishments (Assessment in 2015 Required)**	$200,000		
11	**Condenser Waterbox Refurbishments (Possible Plasticor Treatment)**	$275,000		

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12	Cycle Isolations - Valves and Steam Trap Replacements as Required (Heat Ra	Routine		
13	Vacuum Pump Refurbishment / Replacement Project	$450,000		
Total		$2,770,000	$40,000	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q1, 2015 – Completion of Siemens RCFA on IP Row21 Blading	March 31, 2015
3	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
4	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015
5	Mid Q2, 2016 - Project Activated for IP Row21 Blading and Begin Procurement Process	May 15, 2016

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unpreparedness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2	IP Turbine Row21 Blading was replaced in 2014 with used blading following a blade tip failure. Depending on RCFA and Forging Availability, IP Row21 Blading could be replaced as early as 2016 although is now targeted for 2017. This could increase capital spending and outage length.	Med	High
3	Turbine LP Inspection could take place in either Fall of 2015 or Spring of 2016. Run hours are being closely monitored. This could reduce scope of outage if done in 2015.	High	Low
4	During the outage major assets will be out of service for an extended period of time (Pending Outage Decision). There is risk of degradation should there be inadequate environmental controls.	Low	High
5	During the outage, major assets will be open (Pending Outage Decision) with large amounts of employees and contractors in the area. Risk of foreign material being dropped or left in the machines.	Low	High
	Define mitigation and / or contingency strategies where probability or impact are high:		
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset		
2	Prepare contingency plan and have blade fixings and materials available should this opportunity arise.		
3	Plant to be prepared for LP Inspection to take place in fall of 2015 or spring of 2016.		
4	Practice environmental controls referencing fleet layup programs		
5	Plan and Implement FME process utilizing fleet standards and practices. Borescope prior to Re-build.		

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Delay	Est. Cost of Delay
12 Hours	$17,500
24 Hours	$31,900
48 Hours	$46,400

Agreement			
Outage Manager:	Tim Gillis	Date:	April 2/15
Outage Owner:	Tony [illegible]	Date:	April 1/15
Executive Owner:	[illegible]	Date:	Apr. 17/15

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Tufts Cove Generating Station	Unit:	6

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Tim Gillis

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	28-May-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	25-Jun-16	Time:	-	Time to Recall (Days / Hours)	5 Days
Commercial Operation	26-Jun-16	Time:	-	Estimated Cost to Recall	$38,700

COMMENTS: (Driver for timeline, Include interaction and impacts on other outages, generation and/or transmission)
Start Date Tied to TUC4 / TUC5 Outages for 2016. Highly preferable not to overlap with another TUC 1/2/3 Outage.
4 Week Minor Maintenance Outage as per Fleet Maintenance Program.
Recall may be Possible. Depends on Outage Progress and Final Scope.
Estimated Cost to Recall Based on Tufts Cove "Unit Outage Delay" Labour Costs for 40Hrs. (5 Days / 8 Hrs per Day)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	**4 Week Minor Outage Maintenance Activities ($120,000 / Week)**	$480,000		
2	**NERC PMs, Relay and UPS**	Included		
3	**Pressure Safety Valves Testing & Re-Certification (All Systems)**	$50,000		
4	**IST Boiler Inspection & Sampling**	$50,000		
Total		$580,000	$0	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	**Initial HP-LP Turbine Blading Inspection (4 Year Half Joint Inspection)**			
	Remove HP / IP Covers and Halfjoint Inspection	$300,000		
	Mitsubishi TFA Support	$80,000		
	Check Interior for Erosion, Corrosion, and Impact Damage	Included		
	Visual, MPI Bladepath, Roots, Blade Fixings, Etc.	$20,000		
	Check Nozzles, Diaphraagms, Labyrinth Packing.	Included		
	Check Governing Mechanism sliding parts for friction or looseness	Included		
	Confirm Rotor Clearances as per Supplied Mitsubishi Clearance Map	Included		
	Check Casing Drains and strainers for any debris	Included		
	Clearances - Nozzles, Shrouded Blades, Rotor & Laby Glands / Oil Seals	Included		
	Check Journal and Thrust Bearings for Wear, Rubs, and Debris	Included		
	Check Strainers, Filters, Coolers, Etc. on Auxillaries	Included		
	Inspect Last Stage LP Blading and Erosion Shields for Wear	Included		
	Contingency for Blading / Gland / Bearing / Hardware Repairs if Required		80,000	Yes
	Grease Spherical Bearing and Valve Linkages	Included		
2	**Initial Turbine Valves Inspection (4 Year Main/Induction Stops & Governors)**			
	Inspect Governors and Stop Valves Bushings, Spindles, and Seats	$150,000		
	Check Hydraulic Amplifier and Linkages	Included		
	Contingency for Valve Component / Hardware Replacements if Required		$50,000	Yes
3	**Condenser Waterbox Refurbishments (If not Completed in 2015)**	$350,000		
4	**Vacuum Pump Cooler Replacements (If City Water not utilized in 2015)**	$50,000		
Total		$950,000	$130,000	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2	Initial Unit6 Turbine Inspection still under review. Although ideal to take place during TUC4/5 Majors, it may be likely that the project be deferred due to cost and running hours.	High	Low
3			

	Define mitigation and / or contingency stratagies where probability or impact are high:
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	Clearly communicate risk of project not going ahead, plan to be ready to execute initial inspection if opportunity presents itself.
3	

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$17,500
24 Hours	$31,900
48 Hours	$46,400

Agreement

Outage Manager:	Tim Gillis	Date:	april 2/15
Outage Owner:	[signature]	Date:	April 1/15
Executive Owner:	[signature]	Date:	Apr 17/15

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Burnside Combustion Turbines	Unit:	1

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Robert Cooper

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, Insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	25-Jul-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	08-Aug-16	Time:	-	Time to Recall (Days / Hours)	4 Days
Commercial Operation	08-Aug-16	Time:	-	Estimated Cost to Recall	$27,248

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
2 Week Minor Maintenance Outage, Outage Starts on Mondays is preferable for CTs.
Re-Call May be Possible, Based on Outage Progress at the time.
Estimate Cost to Recall roughly based on "Cost of Delay Unit Starts for Tufts Cove"
Outage Timeline could grow if capital work identified as contingency below is not deferred and executed in 2016.
Engine Refurbishment could increase outage timeline to 4 Months if executed in 2016.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	2 Week Minor Outage Maintenance Activities ($ / Week)	$215,000		
2	Balance of Plant Preventative Maintenance Activities	Included		
3	Balance of Plant Corrective Maintenance Activities	Included		
4	Full Hot Section Inspection	$38,500		
5	Field Inspection of Welded Free Turbine Vanes (Completed in 2015)	Included	70,000	
Total		$253,500	$70,000	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	BGT1 Engine Refurbishment (Deferred from 2015. Depends on whether BG4 will be done in 2015. If not, spare engine will be utilized for BG1. Because it is currently unkown if this will take place in 2016, it is recorded as "Contingency".)		$1,168,167	
2	Generator Rotor Out Inspection (Included in Retain Rings Replacement - CAP. Inspection and Retaining Ring Replacement is unlikely to happen in 2016 so is recorded as "Contingency".)		$150,000	
3	BGT1 Generator Retaining Ring Replacement (Deferred from 2015, linked to "Generator Rotor Out Inspection". May Defer to 2017)		$375,868	
4	BGT1 - Flux Probe & Partial Discharge (Deferred from 2015, linked to "Generator Rotor Out Inspection" and "Retaining Ring Replacement".)		$65,649	
5	BGT1 - PLC & Field Device Control Systems Upgrades (Deferred from 2015, Going forward if capital spending is reduced, this project may be applied to another unit, Will be recorded under "Contingency".)		$253,767	
6	BGT1 - Vibration Monitoring System (TGA Assessments, Linked to "PLC and Control Systems Project" Recorded as Contingency.)		$251,988	
7	BGT1 - Lube Oil Filter Upgrades (Currently Reviewing Project)	$30,000		
Total		$30,000	$2,265,439	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low

2	Due to many 2016 projects being dependant on 2015 outages and capital spending, many projects for BG1 are currently on hold. Risk that late approval or deferral of investment to another unit coould affect prepardness and execution in 2016.	Low	High

Define mitigation and / or contingency strategies where probability or impact are high.	
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	Going forward prepare to execute the identified projects until advised otherwise. Make Marketing & ECC aware that possibility of a longer outage could occur if identified work is executed. If all work were to be done, could see unit offline for up to 12-16 Weeks.

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12 hour, 24 hour and 48 hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$6,812
24 Hours	$10,218
48 Hours	$11,921

Agreement

Outage Manager:	[signature]	Date:	May 5, 2015
Outage Owner:	[signature]	Date:	May 6/2015
Executive Owner:	[signature]	Date:	June 1/15

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER
An Emera Company

Plant / Location	Burnside Combustion Turbines	Unit	2

Executive Owner	Dave Pickles
Outage Owner	Tony Stevens
Outage Manager	Robert Cooper

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	04-Jul-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	18-Jul-16	Time:	-	Time to Recall (Days / Hours)	4 Days
Commercial Operation	18-Jul-16	Time:	-	Estimated Cost to Recall	$27,248

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
2 Week Minor Maintenance Outage, Outage Starts on Mondays is preferable for CTs.
Outage Could be Extended Should a Generator Refurbishment be Required.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	2 Week Minor Outage Maintenance Activities ($ / Week)	$215,000		
2	Balance of Plant Preventative Maintenance Activities	Included		
3	Balance of Plant Corrective Maintenance Activities	Included		
4	Full Hot Section Inspection	$38,500		
5	Field Inspection of Welded Free Turbine Vanes (Completed 2015)	Included	70,000	
Total		$253,500	$70,000	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	BGT2 - Clutch Switch Improvements (Possible Deferral to 2017)		$30,000	
2	BGT2 - Lube Oil Filter Upgrades (TGA Assessments)	$30,000		
Total		$30,000	$30,000	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low

	Define mitigation and / or contingency strategies where probability or impact are high.
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$6,812
24 Hours	$10,218
48 Hours	$11,921

Agreement

Outage Manager:		Date:	May 5/15
Outage Owner:		Date:	May 6/15
Executive Owner:		Date:	June 1/15

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Burnside Combustion Turbines	Unit:	3

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Robert Cooper

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, Insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC/FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	15-Aug-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	05-Sep-16	Time:	-	Time to Recall (Days / Hours)	5 Days
Commercial Operation	05-Sep-16	Time:	-	Estimated Cost to Recall	$34,060

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
3 Week Minor Maintenance Outage, Outage Starts on Mondays is preferable for CTs.
Re-Call May be Possible, Based on Outage and Capital Progress at the time. 5 Day Recall Should Capital be executed.
Estimate Cost to Recall roughly based on "Cost of Delay Unit Starts for Tufts Cove"

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	3 Week Minor Outage Maintenance Activities ($ / Week)	$215,000		
2	Balance of Plant Preventative Maintenance Activities	Included		
3	Balance of Plant Corrective Maintenance Activities	Included		
4	Full Hot Section Inspection (TGA Assessment 2016)	$38,500		
5	Field Inspection of Welded Free Turbine Vanes (Completed 2015)	Included	70,000	
Total		$215,000	$70,000	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	BGT3 - Gas Generator Shop Inspection (TGA Assessments Target 2016, However likely not going to take place until 2017-2018 due to BG4)		1,200,000	
2	BGT3 - PLC & Field Device Control Systems Upgrades (TGA Target 2016)	$253,767		
3	BGT3 - Flux Probe & Partial Discharge (TGA Target 2016, May get Done in 2015, However is linked to Generator Projects)		$65,649	
4	BGT3 - Vibration Monitoring System (TGA Assessments 2016)	$251,988		
5	BGT3 - Clutch Switch Improvements (2015 - Cancelled?)	$30,000		
6	BGT3 - Lube Oil Filter Upgrades (TGA Assessments 2016)	$30,000		
Total		$565,755	$1,265,649	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2			

	Define mitigation and / or contingency strategies where probability or impact are high:
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	
3	

Delay of Outage Start

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$6,812
24 Hours	$10,218
48 Hours	$11,921

Agreement			
Outage Manager:		Date:	May 5/15
Outage Owner:		Date:	May 6/15
Executive Owner:		Date:	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER
An Emera Company

Plant / Location:	Burnside Combustion Turbines	Unit:	4

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Robert Cooper

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage Inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, Insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	N/A	Time:	-	Is a Recall Possible?	N/A
First Re-Sync	N/A	Time:	-	Time to Recall (Days / Hours)	-
Commercial Operation	N/A	Time:	-	Estimated Cost to Recall	-

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
Awaiting Unit Restoration Project Approval. No TMS Timeframe Required.

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	7 Week Minor Outage Maintenance Activities ($ / Week)	$215,000		
2	Balance of Plant Preventative Maintenance Activities	Included		
3	Balance of Plant Corrective Maintenance Activities	Included		
4	Full Hot Section Inspection (TGA Assessment 2016)	$38,500		
Total		$253,500	$0	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	BGT4 Unit Restoration (Phase 2 - New Generator, FT, Auxillarles. Engine (Done) Awaiting Approval in 2015, Most work will take place in 2016)	$9,000,000		
Total		$9,000,000	$0	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2			

	Define mitigation and / or contingency strategies where probability or impact are high:
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	N/A
24 Hours	N/A
48 Hours	N/A

Agreement			
Outage Manager:		Date:	May 5/15
Outage Owner:		Date:	May 6/15
Executive Owner:		Date:	June 1/15

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER
An Emera Company

Plant / Location:	Tufts Cove Combustion Turbines	Unit:	4

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Robert Cooper

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	10-Oct-16	Time:	-	Is a Recall Possible?	No
First Re-Sync	14-Nov-16	Time:	-	Time to Recall (Days / Hours)	-
Commercial Operation	14-Nov-16	Time:	-	Estimated Cost to Recall	-

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
5 Week Minor Maintenance Outage, Outage Starts on Mondays is preferable for CTs.
No Recall Available - Generator Out Inspection
Outage Could be Extended Should a Generator Refurbishment be Required.

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	5 Week Minor Outage Maintenance Activities ($ / Week)	$250,000		
Total		$250,000	$0	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	TUC4 LM6000 - Generator Rotor Out Inspection (CAP)	$200,000	1,500,000	
2	TUC4 LM6000 - Air House Modifications (If Not Completed in 2015)	$300,000		
3	TUC4 LM6000 Hydraulic Pumps (If not done in 2015)	$318,000		
Total		$818,000	$1,500,000	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2	Risk that Generator Out Inspection reveals that a Rotor Refurbishment will be required.	Med	High
3			

	Define mitigation and / or contingency strategies where probability or impact are high
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	Prepare Contingency Plan for Rotor Refurbishment should it be immediately required.
3	

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$6,812
24 Hours	$10,218
48 Hours	$11,921

Agreement			
Outage Manager:		Date:	May 5/15
Outage Owner:		Date:	May 6/15
Executive Owner:		Date:	June 1/15

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER
An Emera Company

Plant / Location:	Tufts Cove Combustion Turbines	Unit:	5

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Robert Cooper

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	06-Sep-16	Time:	-	Is a Recall Possible?	No
First Re-Sync	11-Oct-16	Time:	-	Time to Recall (Days / Hours)	-
Commercial Operation	11-Oct-16	Time:	-	Estimated Cost to Recall	-

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
5 Week Minor Maintenance Outage, Outage Starts on Mondays is preferable for CTs. (September 5th is a Holiday)
No Recall Available - Generator Out Inspection
Outage Could be Extended Should a Generator Refurbishment be Required.

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	5 Week Minor Outage Maintenance Activities ($ / Week)	$250,000		
Total		$250,000	$0	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	TUC5 - LM6000 Generator Rotor Out Inspection	$150,000	1,500,000	
2	TUC5 - LM6000 Hydraulic Pumps (If not done in 2015)	$318,000		
Total		$468,000	$1,500,000	

CAPITAL → MARK 6 CONTROLS · UPGRADES $300,000 - $400,000

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2	Risk that Generator Out Inspection reveals that a Rotor Refurbishment will be required.	Med	High
3			

	Define mitigation and / or contingency strategies where probability or impact are high
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	Prepare Contingency Plan for Rotor Refurbishment should it be immediately required.
3	

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$6,812
24 Hours	$10,218
48 Hours	$11,921

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Agreement			
Outage Manager:	[signature]	Date:	May 5/15
Outage Owner:	[signature]	Date:	May 6/15
Executive Owner:	[signature]	Date:	June 1/15

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location	Tusket Combustion Turbines	Unit	1

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Robert Cooper

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	06-Jun-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	27-Jun-16	Time:	-	Time to Recall (Days / Hours)	4 Days
Commercial Operation	27-Jun-16	Time:	-	Estimated Cost to Recall	$27,248

COMMENTS: (Driver for timeline, Include interaction and impacts on other outages, generation and/or transmission)
3 Week Minor Maintenance Outage, Outage Starts on Mondays is preferable for CTs.
Re-Call May be Possible, Based on Outage Progress at the time.
Estimate Cost to Recall roughly based on "Cost of Delay Unit Starts for Tufts Cove"
3 Weeks Required for Controls Upgrades.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	3 Week Minor Outage Maintenance Activities ($ / Week)	$290,000		
2	Balance of Plant Preventative Maintenance Activities	Included		
3	Balance of Plant Corrective Maintenance Activities	Included		
4	Full Hot Section Inspection (TGA Assessment 2016)	$38,500		
Total		$290,000	$0	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	Tusket Controls Systems Upgrades (Deferred from 2015)	$442,000		
2	Tusket Fuel Tank Upgrades			
Total		$442,000	$0	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2			
	Define mitigation and / or contingency stratagies where probability or impact are high		
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.		
2			

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12 hour, 24 hour and 48 hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$6,812
24 Hours	$10,218
48 Hours	$11,921

Agreement

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Outage Manager	Rob Cooper	Date:	May 5/15
Outage Owner	[illegible]	Date:	May 6/15
Executive Owner	[illegible]	Date:	June 1/15

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER
An Emera Company

Plant / Location:	Victoria Junction Combustion Turbines	Unit:	1

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Robert Cooper

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, Insurers recommendations, root cause failure analyses, and other sources.

Shutdown Targets and Deliverables

1	No Lost Time or Medical Aid Incidents
2	No Environmental Incidents.
3	Execute the planned work during the Outages safely, on time and on budget.
4	Identify long-lead materials and track to delivery in time for Outage execution.
5	Identify Contract work associated with the Outage, and have RFPs/RFQs prepared to allow Contract finalization in advance of Outage start.
6	100% of identified "High Priority" work completed, 70% of "Medium Priority" work completed.
7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC-FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	02-May-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	16-May-16	Time:	-	Time to Recall (Days / Hours)	4 Days
Commercial Operation	16-May-16	Time:	-	Estimated Cost to Recall	$27,248

COMMENTS (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
2 Week Minor Maintenance Outage, Outage Starts on Mondays is preferable for CTs.
Re-Call May be Possible, Based on Outage Progress at the time.
Estimate Cost to Recall roughly based on "Cost of Delay Unit Starts for Tufts Cove"

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	2 Week Minor Outage Maintenance Activities ($ / Week)	$290,000		
2	Balance of Plant Preventative Maintenance Activities	Included		
3	Balance of Plant Corrective Maintenance Activities	Included		
4	Hot Section Inspection (TGA Assessment 2016)	$76,000		
5	Generator Rotor In Inspection (TGA Assessment 2016)	$36,000		
Total		$402,000	$0	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Mat'ls
1	Hydraulic Start Systems Upgrades (Depends on Success with Tusket Project in 2015, Recorded as "Contingency")		$300,000	
Total		$0	$300,000	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
2	End of Q2, 2015 – Finalized capital plan, more accurate work scope (labour plan) and budget	June 30, 2015
3	End of Q3, 2015 – Finalized budget, capital program and maintenance scope.	September 30, 2015

Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2			

	Define mitigation and / or contingency strategies where probability or impact are high.
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	

Delay of Outage Start

To facilitate dispatch decisions by marketing, provide an estimate for a 12-hour, 24-hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

Delay	Est. Cost of Delay
12 Hours	$6,812
24 Hours	$10,218
48 Hours	$11,921

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Agreement			
Outage Manager:	[signature]	Date:	May 5/15
Outage Owner:	[signature]	Date:	May 6/15
Executive Owner:	[signature]	Date:	June 1/15

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016 PLANNED OUTAGE CHARTER

Nova Scotia POWER An Emera Company

Plant / Location:	Victoria Junction Combustion Turbines	Unit:	2

Executive Owner:	Dave Pickles
Outage Owner:	Tony Stevens
Outage Manager:	Robert Cooper

Background Information

The Charter is based on the Standardized Outage Quality Process. The charter identifies our major Outage activities for the upcoming Outage, and provides a high level overview of the scope and budget. There are a number of capital projects, maintenance, and inspections scheduled which will require the generating units to be off-line. The inspections and projects may be time stamped, some are driven from OEM recommendations, some are guided by standards and regulations, and others by plant maintenance practices and programs. These high level items may be identified through thorough review of previous Outage inspections, asset health assessments and Reliability Teams, Equipment Maintenance & Operating History, insurers recommendations, root cause failure analyses, and other sources.

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4	Identify long-lead materials and track to delivery in time for Outage execution.
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7	Document the Outage and utilize the tools developed through the Outage Standardization Process to support both internal, and external auditing processes. Special focus to be taken to identify and record risks, change and learnings.
8	Prepare scope and budgets as required to meet Milestones for Capital, Operating and Outage Planning.

Outage TMS Request

All information submitted in this process will be used by the NSP solely in support of its obligations under NERC, FAM and associated policies, standards and procedures. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Start Date	16-May-16	Time:	-	Is a Recall Possible?	Yes
First Re-Sync	30-May-16	Time:	-	Time to Recall (Days / Hours)	4 Days
Commercial Operation	30-May-16	Time:	-	Estimated Cost to Recall	$27,248

COMMENTS: (Driver for timeline, include interaction and impacts on other outages, generation and/or transmission)
2 Week Minor Maintenance Outage, Outage Starts on Mondays is preferable for CTs.
Re-Call May be Possible, Based on Outage Progress at the time.
Estimate Cost to Recall roughly based on "Cost of Delay Unit Starts for Tufts Cove"

Operating Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	2 Week Minor Outage Maintenance Activities ($ / Week)	$290,000		
2	Balance of Plant Preventative Maintenance Activities	Included		
3	Balance of Plant Corrective Maintenance Activities	Included		
4	Quick Hot Section Inspection (TGA Assessment 2016)	$76,000		
5	Generator Rotor In Inspection (TGA Assessment 2016)	$36,000		
6	Field Inspection of Welded Free Turbine Vanes	Included	$70,000	
Total		$402,000	$70,000	

Capital Overview and High Level Budget

	Item Description	Budget	Contingency Plan	Long Lead Matls
1	Hydraulic Start Systems Upgrades (Depends on Success with Tusket Project in 2015, Recorded as "Contingency")		$300,000	
Total		$0	$300,000	

Planning Milestones

	Milestone	Date
1	End of Q1, 2015 – Finalized work plan, draft capital list, draft budget	March 31, 2015
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Risk Identification

	Risks	Probability	Impact
1	Late identification or approval of scope may result in unprepardness for the outage. (Materials not procured, Contracts not finalized, Proper budgets not in place, Etc.)	Low	Low
2			

	Define mitigation and / or contingency strategies where probability or impact are high
1	Consider possible contingency scenarios should something be found. Manage through with support from Asset Management team and industry experts to determine best path forward for any unplanned repairs.
2	

Delay of Outage Start

To facilitate dispatch decisions by Marketing, provide an estimate for a 12-hour, 24 hour and 48-hour delay to the Outage Start, assuming the Return to Service date would have to stay the same.

QP-G001 Shutdown Standardization
Planned Outage Charter
Asset Management Office

Combustion Turbines - 2016
06/05/2015

Delay	Est. Cost of Delay
12 Hours	$6,812
24 Hours	$10,218
48 Hours	$11,921

Agreement			
Outage Manager	[signature]	Date	May 5/15
Outage Owner	[signature]	Date	May 6/15
Executive Owner	[signature]	Date	June 1/15

Request IR-19:

Please provide a detailed explanation of NSPI's long-term operating strategy for each of the Lingan generating units, including the age of each unit, the estimated remaining operating life of each unit, and projected major capital spending projects over the next 5 years. Please also specify how the operating strategy has been updated or changed since the previous ACE Plan was filed.

Response IR-19:

Lingan 1 – Commissioned 1979, Forecasted operating life beyond 15 years:

- Lingan 1 is a flexible unit with two-shifting capability and no significant operating limitations.
- Asset planning is based on gradual reduction in capacity factor and service hours offset by increased two-shift utilization to the end of the decade.
- Post 2020, it is anticipated that this unit will see ultra-low utilization for more than a decade.
- Based on the anticipated reduction in future utilization, major investments are not planned at this time. Tactical investments will be made based on year over year assessments.
- There is no change in operating strategy since the last ACE submission.

Lingan 2 – Commissioned 1980; Forecasted operating life until 2018:

- Lingan 2 is being life managed with anticipated retirement in 2018.

- Major outages and investments are being avoided in this unit.

- Risks are being mitigated with operating limitations:

    - Restricted stop/start cycles
    - Long duration layups to preserve remaining life for winter operation

- There is no change in operating strategy since the last ACE submission.

Lingan 3 – Commissioned 1983, Forecasted operating life beyond 20 years:

- Lingan 3 has undergone a major refit in 2015 and has been positioned for full service and flexible operation.

- Lingan 3 is anticipated to be operational for several more major maintenance intervals (decades).

- This unit will continue to have investments in all asset classes similar to historical. The next major maintenance interval is planned for 2023.

- There is no change in operating strategy since the last ACE submission.

Lingan 4 – Commissioned 1984, Forecasted operating life beyond 20 years:

- Lingan 4 will undergo a major refit in 2016 and has been positioned for full service and flexible operation.

- Major investments include:

- L-0 LP Turbine Blades
- Generator Rotor
- Generator retaining rings

- Lingan 4 is anticipated to be operational for several more major maintenance intervals (decades).

- This unit will continue to have investments in all asset classes similar to historical. The next major maintenance interval is planned for 2024.

- There is no change in operating strategy since the 2015 ACE Plan submission.

Request IR-20:

For CI# 47658:

(a) Did the L-0 blades ever require maintenance in the past? If so, please provide the date(s) and explain the maintenance done to the blades.

(b) Please provide any evaluations, reports, or inspection studies performed to indicate that the blades are at their end of life and replacement is recommended.

(c) If the blades have not been an issue in the past, then why are recent signs of erosion and risk of blade separation a cause for immediate concern?

(d) When is the Lingan #4 unit expected to be retired?

Response IR-20:

(a) The maintenance strategy includes annual inspection requirements of the exhaust end of the L-0 Blades via the steam space in the condenser. Previous maintenance included modest remedial work to address inspection findings and include: blade fastening pin replacements and shield replacements. Please refer to Attachment 1 (excerpt from Lingan 4 TGA Turbine Assessment). In the report TGA summarizes historical outage work. As indicated, there were only inspection activities on LP blades with no actionable findings in 1998 and 1996. In 2008 there were findings requiring modest repair (pins and shields) and the first indication from OEM that L-0 blades would require future replacement. In 2011, TGA reinforced that a plan for replacement was required and ongoing monitoring of condition necessary to mitigate risks. Ongoing monitoring of condition and anticipated utilization of has lead NS Power to act on L-0 blade replacement in 2016.

(b) Please refer to Attachment 1 (excerpt from Lingan 4 TGA Turbine Assessment). Advanced erosion is an ongoing risk that continues to worsen with service life expended and changing unit operating mission profiles. In 2008 the OEM indicated need to plan for replacement (Attachment 1). In 2011 TGA indicated need to develop plan for replacement (Attachment 1).

(c) The blade life has been managed. While there is no immediate concern of failure, there would be much concern about operating these blades to the next maintenance interval (Approximately 8 years). The L-0 blades on Lingan 4 are original with approximately 240,000 operating hours as of 2015. They are approaching end of life.

Given the accumulated running hours, projected operation, known erosion, and experience with Lingan 3, it has been determined that the blades should be replaced during its next scheduled inspection in 2016.

(d) Please refer to NSUARB IR-44.

Lingan Unit 4
Turbine-Generator Health Assessment October, 2011
TG Advisers, Inc. (10)
Executive Summary of Outage Reports

Annual Overhaul Maintenance Activity

June 1988

Scope of Report

This summary documents the 1988 annual overhaul maintenance activities on Lingan Unit 4.

Summary

- The turbine main steam stop valve was stripped and inspected. The valve was found in good condition, by-pass valve stroke checked and found within tolerance and spindle bushings clearances restored to acceptable design tolerance. The M.S.V. strainer mesh welds were all dye checked and found to be o.k.
- The lower control valves were dismantled, inspected, bushings honed and clearances restored to design tolerance. New camshaft bushings were installed and one spring stud bolt required replacement.
- Oil baffles from #1 and #2 bearings were removed, cleaned, inspected and reinstalled.
- Final stage blading in the L.P. rotor was inspected at turbine and generator ends and found in good condition. Rubber mold impressions of the L.P. blading and exhaust flares were taken for future reference.
- The seal oil vacuum tank was drained, cleaned and inspected. All internals found in good condition.
- The A.C. seal oil pump was replaced.
- Both turbine lube oil coolers were opened, cleaned and inspected. No defects were noted.

Recommendations

No recommendations were given in this report.

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Lingan Unit 4
Turbine-Generator Health Assessment October, 2011
TG Advisers, Inc. (25)
Executive Summary of Outage Reports

Turbine Overhaul Inspection Report
Toshiba Corporation
May 1996

Scope of Report
This summary documents turbine overhaul findings as reported by the Toshiba service engineer (author unknown) during the 1996 turbine/generator inspection.

Summary
HP Outer Casing
- Heavy scaling on horizontal joint and sealing surfaces. Polished with stone.
- Packing head spigot fit to casings had some scuffing. Repaired by filing and stoning.
- Visual inspection – good

HP Inner Casing
- Heavy scaling on horizontal joint and sealing surfaces. Polished with stone.
- Drilled out and replaced bolts #70 (4”) and #74 & #76 (3.5”)
- Replaced nuts #70, #72, #74, #74, #75, #76
- Vibration induced damage to gib keyway on gen. side upper half. Used as is.
- Mag particle and ultrasonic test was good. (No specific inspection report)
- Visual inspection – good
- Replaced upper half nozzle diaphragm pins and set screws

IP Inner Casing
- Heavy scaling on horizontal joint and sealing surfaces. Polished with stone.
- Vibration induced damage to gib keyway on turb. side upper half. Replaced gib key bolts.
- Mag particle and ultrasonic test was good. (No specific inspection report)
- Visual inspection – good

LP Outer Casing
- Visual inspection – good
- No erosion found.

LP Inner Casing
- Horizontal joint erosion. Repair welded
- Erosion found at drain hole of diaphragm #19. No repair noted
- Erosion found on steam guide plates. Weld repaired.
- Replaced bolts nos. 80, 81, 82, 83, 87, 89
- Mag particle test found indication on lower half of horizontal joint. Repair welded.

Nozzle Diaphragms (HP/IP/LP)

- Mag particle tested.
- Replaced dowel pin on IP #9&11
- Repaired damaged fins and bent nozzle partitions (no specific repairs were noted)

HP Rotor

- Rubbing between spill strips and shroud cover plates on stages HP-2,3,4 and IP 8,9,10,11.
- Removed foreign material on back side of shroud cover plates on HP stages 2,3,4.
- Visually inspected journals, thrust collar, emergency trip ring, coupling surfaces, coupling bolt holes – all found in good condition.
- Found zero clearance between shroud cover plates and blades
- #1, 2, 3 gland packing areas in good condition
- Mag particle test. Results good.

LP Rotor

- Erosion on T20 and G20 blades
- Mag particle test. Results good.
- Visually inspected journals, coupling surfaces, coupling bolt holes. Found #3 journal damaged by foreign material in lube oil. Repaired scuffed coupling bolt holes.
- #4, 5 gland packing areas in good condition.
- Found zero clearance between shroud cover plates and blades.
- Turning gear ring contact good.

Bearings

- #1 – PT check and contact between journal and pad metal was good.
- #2 – PT check and contact between journal and pad metal was good.
- #3 – PT check found separation. Also babbitt damage. Repaired.
- #4 – PT check found separation. Contact between journal and babbitt was good.
- Thrust bearing – Repaired minor pad damage. Contact between pads and thrust collar was good.

Speed governor

- Realigned (shim replacement)
- Spline shaft contact, drive backlash and gear teeth contact were good.

Emergency Trip Device

- Clearance adjusted with shims (1.18 mm to 1.75 mm)

Turning Gear

- Gear tooth contact and backlash were good.

Alignment

- Found HP to LP rotor out of alignment. Corrected by shimming #1 and #2 bearings.

Recommendations

This report contained no recommendation.

Lingan Unit 4
Turbine-Generator Health Assessment October, 2011
TG Advisers, Inc. (49)
Executive Summary of Outage Reports

Toshiba 4 Overhaul Outage Report

October 2008
(Shigeru Tsuji)

Scope of Report

This summary documents the report issued by Toshiba, covering the overhaul of the Lingan Unit 4 turbine and generator in 2008. The report includes an addendum, authored by Mr. Tsuji, listing specific recommendations for the next outage. This was redundant to the recommendations found in the main body of the report. For ease of review, all future outage recommendations listed have been included in one recommendations section. Details of the generator overhaul are described in a separate report.

Summary

- Lingan Power Stations portion of the scope of work included the HP/IP Turbine disassemble/inspection/reassembly, LP Turbine disassemble/inspection/reassemble, Generator disassemble/inspection/rewedge/reassemble and valve disassemble/inspections/reassembly.
- Toshiba and ReGenCo's portion of the scope of work included providing technical direction, inspection assistance and re-wedging the generator.
- Additional scope added to ReGenCo and Reliable Turbine Services (RTS) was a weld repair to #8 diaphragm partitions.
- Additional scope added to ReGenCo was repair to 1st stage diaphragm partitions.
- The HP/IP and LP Turbine scope included bore inspection of the rotors, outer cylinders, inner cylinders, diaphragms, inner/outer glands, and front standard on site.
- The generator scope of work included inspection and testing of the stator and rotor, re-wedge work, and H2 cooler work on site.
- The valve scope of work included inspection of the MSV, Control Valves, and CRV internal components.

Recommendations

Recommendations listed in the Tsuji addenda were accompanied by a priority key per the following:

- (A) Reexamine the problem at a future inspection
- (AA) Suggest repair at the next inspection
- (AAA) Recommend repair at the next inspection

HP/IP Section

- Perform TTIL-KS91002X for nozzle support pins.
- Found excessive clearance and tooth damage on HP gland packing rings #1, #2, and #3. Replace packing rings and perform Tops On/Tops Off alignment. Priority (AAA)
- Inner casing horizontal joint stud #53. Replace with new stud. Priority (AAA)

- Outer casing horizontal joint studs #1 and #2. Found bent and touching casing holes. Replace studs. Priority (AAA)
- Found key slot damage on running keys at TR, TL, GR, and GL. Replace all (4) keys. Priority (AAA)
- HP 7th stage, IP 8th stage and IP 14th stage nozzles had damaged Z-1 long teeth on the upper and lower halves. Replace all Z-1 teeth. Priority (AAA)
- IP 8th stage damaged due to steam erosion. Replace nozzle. Priority (none given)
- Replace all HP/IP packing, due to excessive clearances.

LP Section
- Broken pin found on last stage blade T-20 on turbine end. Replace pin. Priority (AAA)
- Found L-0 erosion shield plates worn. Recommend possible replacement. Priority (AAA)

Bearings

- Excessive oil fin wear on bearings #1 and #2. Replace all fins. Priority (AAA) May be duplicate recommendation – Retooth 1G and 4G oil deflectors

Valves (general)
- Have lapping tools on hand for valve seats and stem guide seats. Minimum machining is required for the stem guide packing face and valve bodies on the MSV and CRV. Priority (AAA)

Main Stop Valve
- Replace stem due to excessive runout. Priority (AAA)
- Head cap does not have additional room for staking of head bolts. Replace head cap. Note: Head cap can be machined one time in lieu of replacement. Priority (AAA)

Control Valves
- Replace CV2 valve stem due to excessive wear. Priority (AAA)
- Replace CV4 and CV8 valve stems due to excessive runout. Priority (AAA)
- Have spare parts on hand for valve CV3 (stem and bushings). Priority (AAA)
- Replace CV8 upper and lower bushings, due to excessive clearances. Priority (AAA)

Rotor Couplings
- Coupling up of HP and LP rotors was difficult. Redress spigot fits. Priority (AAA)

Work Performed

HP/IP Turbine
- Disassembled and inspected components to include outer cylinder, inner cylinders, rotor, bearing, diaphragms, packings, and gland seals. Additional work required included an incol 82 partition weld repair on #8 diaphragm, correcting bad blue contact checks for #1 and #2 bearings, NDE and bonding check of # 1 and #2 bearing, blast cleaning of components, NDE and bore scope of rotor, and NDE of casing studs.

LP Turbine

- Disassembled and inspected components to include outer cylinder, inner cylinders, rotor, bearing, diaphragms, packings, and gland seals. Additional work required included a blue check and repair of the inner cylinder, correcting bad blue contact checks for #3 and #4 bearings, NDE and bonding check of #3 and #4 bearing, blast cleaning of components, NDE and borescope of rotor, drilling out and replacing horizontal joint bolts. Gland packing heads for 4 and 5 were replaced.

Main Stop Valve
- Disassembled, inspected components and reassembled. Found in fair running condition; see exception in Summary of Recommendations.

Control Valves
- Disassembled, inspected components and reassembled. Found in fair running condition; see exception in Summary of Recommendations.

CRV Valve
- Disassembled, inspected components and reassembled. Found in fair running condition; see exception in Summary of Recommendations.

Front Standard
- Disassembled, cleaned, inspected and reassembled. Found in fair running condition; see exception in Summary of Recommendations.

Main Oil Pump
- Disassembled, cleaned, inspected and reassembled. Found in good running condition.

Thrust Bearing
- Disassembled, cleaned, inspected and reassembled. Found in good running condition.

Bearings
- Disassembled, cleaned, blue checked, NDE/bond check, and reassembled. Found in good running condition; see exception in Summary of Recommendations. #3 and #4 bearings were changed out due to excessive clearances.

Oil Deflectors
- Disassembled, cleaned, inspected and reassembled. Found in fair running condition; see exception in Summary of Recommendations.

Turning Gear
- Removed, performed visual inspection and reinstalled. Found in good running condition.

Lube Oil System
- Conducted 24 hour flush.

Generator
- See generator report

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Exciter

- See generator report

Packing

- Disassembled, cleaned, inspected and reassembled. Found in fair running condition; see exception in Summary of Recommendations.

Lingan Unit 4
Problem Area Worksheet

Evaluation				
Issue #	Problem Area	Risk 0-4 (a)	Probability 0-3 (b)	Availability Factor (a) x (b)
DFLP1	Blade/bucket water droplet erosion and FOD damage	4	2.5	10
DFLP2	Diaphragm cracking, SPE and FOD	3	2	6
DFLP3	Blade/bucket foil and tenon cracking and rubs	3	2	6
DFLP4	Blade/bucket tie wire, lacing wire, and/or tip strut cracking	3	2	6
DFLP5	Blade attachment area cracking	4	2	8
DFLP6	Rotor bore cracking	4	1	4
DFLP7	Cylinder/shell cracking, steam leaks and distortion	2	3	6
DFLP8	Last row blade/bucket stall flutter	3	1.5	4.5
DFLP9	Rotor peripheral and shaft end cracking	4	1	4

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Lingan Unit 4
Problem Area Worksheet

ISSUE #: ___*DFLP1*___ Continued from Previous Page

Action Items:

- Continue annual best effort inspection of DFLP back-ends from the condenser or other access points to determine if any unusual erosion or other damage has occurred since the last inspection.
- A pre outage inspection should be made of the erosion shields to make a definitive decision as to the amount of shield replacement required. Any erosion rate as shown by comparing the previously inspections should be incorporate.
- Identify and procure a qualified blade repair contractor prior to next major outage (to include shield replacement and shroud weld repair).
- Incorporate following into the outage plan (all LP ends):
  - Obtain replacement erosion shields (based on pre outage inspection).
  - Complete MT of rotor and blades including accessible shaft radii & surfaces, underside of shroud bands, ferrules, lacing wires, inlet & outlet end faces of axial fit blade roots (as applicable) and blade foils.
  - Perform eddy-current examination of the leading and trailing edges of L-1, L-2 and L-3 rotating rows.
  - Shroud OD dimensional changes (including tile lifting as applicable) .
  - Shroud condition (inspect for radial rubs).
  - Integrity check of the brazed connections (as applicable).
  - Other recommendations are provided in PAW DFLP5 for the blade attachment.
  - Photographs of each row showing general condition as-found and as-left condition.
  - Rubber molds of the erosion shield and shroud areas.
  - Contingency plan for replacement L-0R blades
- Develop forms to capture findings. This will allow development of a baseline for comparison at future outages for changes in blade condition (e.g. being able to track tile lifting).

Investigators: Greg Carlin

Date: June, 2011

NON-CONFIDENTIAL

Request IR-21:

For CI# 47673:

(a) When is the next major planned outage for Lingan Unit #4 after 2016?

(b) Please provide all supporting documentation that shows that the rotor will need to be refurbished.

Response IR-21:

(a) Major outages are typically planned on a base of eight year intervals, with consideration for unit utilization (capacity factor, operating hours, unit starts). In addition, regular health assessments are utilized to refine timing and scope of major outages. Lingan 4 is presently anticipated to have a major outage in 2024.

(b) A summary of TG Advisers assessment of Lingan 4 Turbine/Generator illustrates concerns associated with the generator rotor. Their recommendations include contingency planning for the rewind of the rotor. Please refer to Attachment 1. NS Power Engineering, in consultation with TG Advisers, views replacement necessary to address risk for long term operation.

Futhermore, retaining ring replacement is required during the 2016 outage. The rewind effort requires removal of the retaining rings so there is significant cost advantage to conducting the retaining ring and rotor rewind at the same time.

Turbine Generator Health Assessment
Outage Plan Summary

Plant	Unit #	Issue #	Availability Factor	Problem Description	Major Outage Assessment Plan and Recommended Corrective Action	Action Items Major Outage	Resp. Engr(s)	Next Major Outage Part/Service Provider	Next Major Outage Estimated Cost ($)	Long Term Contingency Plan Cost ($)	Cap (Y/N)	Last Insp. (Year)	Target Insp. Interval (years)	Comments	Inspection Findings	Date Complete
Lingan	4	GEN5	7.5	Rotor winding	• Perform an Insulation Resistance (megger) test at 500 Volts DC and check the Polarization Index. An IR value of at least 20 megohms and a PI of at least 1.5 are desirable. • Check rotor field winding impedance and compare to previous historical test values. A significant change in impedance from previous values, when corrected for varying temperatures, could be an indication of a brazed joint failure. • Check for shorted turns with a pole balance test (also called a pole drop test) if vibration is a concern. • Verify that any field ground alarms are working properly. • Inspect pole crossover and field winding underneath the retaining ring at next major outage. • Perform a pressure test on the radial lead (terminal stud) seals. Replace if needed. • Install a flux probe to monitor shorted turns on-line. • At the next end bells off	• Verify that the pole crossover can be viewed by borescope under the retaining ring with the rotor still installed in the stator. • Look for a short outage window prior to 2018 (planned next major) to inspect the pole crossover. Use a borescope to inspect underneath the end turns of the winding. Look for signs of pole crossover fatigue cracking, migrated turn insulation, arc damage, loose blocking, etc. If the crossover cannot be viewed directly and inspected for cracks, if the borescope can look under the winding at least verification that no arcing or burning (as evidenced by discoloration) can be done. • Verify that any field ground alarms are working properly. • Confirm stock of replacement radial lead seals.	Willard Cameron	Rewind	$1,500,000			2010	2018	Unit 4 rotor rewind, depending on Unit 2 results.		
								Install a flux probe.	$50,000				2018			
								Lead seals and pins (already done on Lingan 1).		$20,000			2018	Stock radial seal pins and O-rings.		

Turbine Generator Health Assessment
Outage Plan Summary

Issue #	Availability Factor	Problem Description	Major Outage Assessment Plan and Recommended Corrective Action	Action Items Major Outage	Resp. Engr(s)	Next Major Outage Part/Service Provider	Next Major Outage Estimated Cost ($)	Long Term Contingency Plan Cost ($)	Cap (Y/N)	Last Insp. (Year)	Target Insp. Interval (years)	Comments	Inspection Findings	Date Complete	
GEN5 (cont'd)			opportunity, plan to inspect the pole crossover with borescope.												

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GEN7	12	Retaining rings	• At next rotor out outage, replace rings with new 18.18 material that is resistant to stress corrosion cracking.	• New 18.18 rings have long lead time for procurement if not in stock. Procure early and reserve if not already done so. • Maintain high level of hydrogen purity. • Ensure hydrogen dryers are properly working and desiccant is "recharging." • Unmachined spare 18.18 rings are in NSPI stock at Trenton 6. Investigate suitability of these spares across the NSPI fleet. Alternatively, investigate contingency plan for commercial swap with vendors, contractors or other owners.	Willard Cameron	Replacement.	$300,000 procure $100,000 install			2008	2018	Includes insulation kit.			

Lingan Unit 4
Problem Area Worksheet

TG Advisers, Inc. (47)
Problem Area Worksheets

ISSUE #: ___GEN5___ AVAILABILITY FACTOR: _ _7.5_ _

Problem Area:
The **Generator Rotor Field Winding** failures are typically electrical in nature. Electrical failures are usually due to shorted turns or electrical grounds. Shorted turns can cause local hot spots (at the location of the short) and uneven heat distribution throughout the winding. Significant uneven heating will typically manifest itself in noticeable vibration from the generator rotor. Multiple turn shorts may even limit the rotors ability to provide adequate magnetizing intensity to the stator which will result in lower generator output. Electrical grounds can be catastrophic if not corrected.
Many generator rotors can operate with one ground (depending on shaft grounding configurations); however, the second ground will cause circulating currents in the rotor body which can overheat the generator rotor body and likely result in a major forced outage situation. Shorts occur due to contamination or failure of the turn insulation. Grounds occur due to failure of the groundwall insulation, contamination, and tracking. Turn insulation and groundwall insulation can fail due to mechanical fatigue (or puncture) or overheating and breakdown of the dielectric properties.

Background and Description:
The rotor field winding consists of individually insulated copper turns, insulated from ground in the slots by insulating cells, and in the end turns by an insulating tube. The field winding carries dc current, and acts as an electromagnet, inducing a voltage in the stator winding.
Spinning at 3600 rpm, large centrifugal forces act on the rotor winding and insulation system. Due to field current heating, and windage and friction, the rotor winding heats up in operation. This adds thermal stress to the insulation system, aging it over time.

- 1986 - Rotor Winding - Rotor winding impedance of 4.67 and capacitance of 0.297 microfarads.

- 1987 - Rotor winding impedance was 4.62 ohms. Capacitance 365 nFarads. PF of 1.04 at 10 kV.

- 1988 - Capacitance and impedance tests on rotor. Rotor winding impedance of 4.68. Rotor capacitance of 0.291 microfarads.

- 1990 - Lingan 4 generator rotor field winding impedance measured 4.515 ohms and capacitance 0.2817 microfarads.

- 1991 - Rotor impedance of 4.82 ohms. Capacitance of 0.279 microfarads.

- 1994 - Rotor impedance of 4.95 ohms. Rotor capacitance at .28 pf.

- 1995 - Rotor impedance of 4.67 ohms and capacitance 279 nf.

Lingan Unit 4
Problem Area Worksheet

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Background and Description (continued):

- 1996 - The rotor transport box was supplied from St. Catharine’s and sent to Lingan for transport of the rotor back to the Parsons' facility in St. Catharine’s. A Field Service Supervisor was sent to Lingan P.S. to witness the loading of the rotor in the box. The box also contained an impact recorder to record any serious bumps the rotor may have had during transportation. Receipt Inspection – The rotor was visually inspected and electrically checked. There was no evidence of any adverse effects. During the inspection at the Parson’s facility in St. Catherines, the rotor end windings did not show any over-heating or distortion and the interturn insulation was good. The nomex portions of the end winding insulation cylinders were creased and torn. The torn Nomex was separated from the glass portions and new nomex was fitted. EE. Radial stalks don’t show signs of leakage. Field winding resistance 0.116 ohms. Rotor IR Checks-Megger readings were taken throughout inspection process and before/after cap replacement. All readings were 1000+ Meg Ohms. Generator Winding OHMIC Resistance - .116 ohms ave. for complete winding (after ring installation and prior to shipment. Rotor Impedance of 4.58 ohms. Capacitance of 0.28 microfarads. Terminal seal leak test: Rotor winding insulation resistance good. Visual inspection of field no problem. Some rust and discoloration. Visual inspection under the retaining ring of the field coils shows no problems. Terminal stud no problem. Pressure test at 300 kPA and vacuum drop test at 100 kPA no leakage. Terminal seal gasket not changed. It’s recommended to change terminal stud gasket every 4 years and check for tightness every 2 years per Toshiba recommendations. Field winding meggered 200 Mohms with 500 volt megger prior to reassembly.

- 1998 - Capacitance and AC Impedance of the rotor were measured. Rotor impedance measured 4.65 ohms (and again at 4.52 ohms after jumpers removed from generator) and capacitance 331.9 nF.

- 1999 - Measured capacitance of the rotor – 0.349 microfarads. Measured AC impedance of the rotor – 4.69 ohms.

- 2002 - Capacitance and AC Impedance of the rotor were measured. Rotor impedance measured 4.89 ohms and capacitance 278 nF. Measured capacitance of the rotor – 277.34 nf. Measured AC impedance of the rotor – 4.65 ohms

- 2003 - Capacitance and AC Impedance of the rotor were measured. Rotor impedance measured 4.58 ohms and capacitance 286 nF.

- 2005 - Rotor impedance measured 4.42 ohms and capacitance 0.2798 pf.

- 2006 - Rotor impedance values of 4.900 ohms and capacitance of 0.2798 microfarads.

- 2007 - Rotor impedance of 4.80 ohms, capacitance of 0.2781 microfarads.

Problem Area Worksheet

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Problem Area Worksheets

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Background and Description (continued):

- 2008 - Generator rotor field (connections broken) – 2.8 MΩ with 500 volt megger. Visual inspection of rotor good. Some rust and discoloration. Did not disassemble and inspect terminal seal gaskets (see recommendations). Rotor terminal seals – replace gasket every 4 years. 2008 - Rotor impedance value of 4.668 and capacitance of 0.2849 microfarads. Rotor was meggered at 500 volts with a ten minute reading of 30.4 Mohms, a PI of 1.33 and a D.A. of 1.04.

- 2009 - Rotor impedance at 4.388 ohms and capacitance at 0.281 microfarads.

- 2010 - Plant Interview - Rotor Field Winding – Rotor has not been rewound. Cracked flex link in pole to pole crossover identified during Unit 1 rotor rewind, follow up on other units. Copper turns are ventilated with holes on units 3 and 4. No flux probe is installed. Estimated # Starts to Present:292 Future cycling 25/ year, 30-40 for plant maybe weekend shutdowns. Estimated Total Operating Hours to 2009: 201485

Preliminary Causes:

- Rotor field winding, like the stator winding has had a remarkable maintenance program effort by the plant and NSP engineering, having testing done each and every year. Test results of impedance and capacitance do show some fluctuation in values and some variability in units. TGA recommends all data to be summarized and trended on a standard test form. Many of these tests are just hand written on a piece of paper, leading to some variance in units. Generator rotor winding issues are typically shorted turn and electrical ground related items that are often caused by: Contamination, Thermal aging and wear of the insulation, Motorizing of the unit (typically damper winding circuit issues). Note that cycling the unit can cause slot cell migration which leads to grounding.

- Pole to pole crossovers and J-strap failures are also common failure modes for field windings. These are typically governed by start/stop cycles (i.e., low cycle fatigue). Lingan 4 has an estimated 291 starts, well below the 421 starts on Lingan 1 with the cracked pole crossover. Lingan 1 field rewound in 2010 had 421 identified start/stop cycles and was discovered to have a pole crossover with about ½ the flexible laminations cracked and failed in fatigue. In addition, Lingan 1 had a field ground prior to the rewind. With four identical units, and units 1 and 2 older with more starts and service hours, events and experiences from these units should be able to be fully leveraged to prevent in-service problems on units 3 and 4. A rotor flux probe installed on all four units is a strong recommendation and can provide valuable information related to any deterioration of the rotor turn insulation.

- Radial stalks (leads)(terminal studs) were reported as not being replaced in 1996 nor in 2008. If they have not been replaced they should be at the next major. Toshiba recommends replacing them every four years.

Lingan Unit 4
Problem Area Worksheet

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Outage Assessment Plan:

- Perform an Insulation Resistance (megger) test at 500 Volts DC and check the Polarization Index. An IR value of at least 20 megohms and a PI of at least 1.5 are desirable.
- Check rotor field winding impedance and compare to previous historical test values. A significant change in impedance from previous values, when corrected for varying temperatures, could be an indication of a brazed joint failure.
- Check for shorted turns with a pole balance test (also called a pole drop test) if vibration is a concern.
- Verify that any field ground alarms are working properly.
- Inspect pole crossover and field winding underneath the retaining ring at next major outage.
- Perform a pressure test on the radial lead (terminal stud) seals. Replace if needed.
- Install a flux probe to monitor shorted turns on-line.
- At the next end bells off opportunity, plan to inspect the pole crossover with borescope.

Action Items:

- Verify that the pole crossover can be viewed by borescope under the retaining ring with the rotor still installed in the stator.
- Look for a short outage window prior to 2018 (planned next major) to inspect the pole crossover. Use a borescope to inspect underneath the end turns of the winding. Look for signs of pole crossover fatigue cracking, migrated turn insulation, arc damage, loose blocking, etc. If the crossover cannot be viewed directly and inspected for cracks, if the borescope can look under the winding at least verification that no arcing or burning (as evidenced by discoloration) can be done.
- Verify that any field ground alarms are working properly.
- Confirm stock of replacement radial lead seals.

Investigators: Willard Cameron
Date: June, 2011

Lingan Unit 4
Problem Area Worksheet
TG Advisers, Inc. (53)
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ISSUE #: ___GEN7___ AVAILABILITY FACTOR: ___12_ _

Problem Area:
The **Generator Rotor Retaining Rings** are very highly stressed components. Retaining Rings can fail from stress corrosion cracking, fatigue cracking, loss of fit, vibration related issues, hydrogen embrittlement, or arc damage leading to premature cracking.

Background and Description:
- Retaining rings support the rotor copper end turn windings during operation. The weight of the copper, being thrown radially outward, imposes severe hoop stresses in the rings. Combined with this stress, the rings can be susceptible to certain kinds of corrosion, fatigue initiated cracking, or hydrogen embrittlement.

1996 - Remove and inspect rotor retaining rings (at Parsons shop). Rotor insulation tests done. This summary documents the rotor end cap (retaining ring) inspection performed by Parsons in 1996, at its St. Catharine’s facility. The retaining rings were removed so that an NDE could be carried out to determine if indications or aqueous stress corrosion were present. The end caps were found with very few indications and were found acceptable to return to service. A small number of areas on the surface of the end caps were examined metallographically. No signs of inclusions or stress corrosion cracking were noted. Recommendations: The end caps should be re-inspected after eight years of operation, after a maloperation (i.e. unbalance due to mis-synchronisation), or after operating in a wet environment. The humidity inside the generator casing should be maintained at approximately 0°C and should not be allowed to exceed +13°C to -20°C. Inspection Details: The rotor transport box was supplied from St. Catharine’s and sent to Lingan for transport of the rotor back to the Parsons' facility in St. Catharine’s. A Field Service Supervisor was sent to Lingan P.S. to witness the loading of the rotor in the box.
The box also contained an impact recorder to record any serious bumps the rotor may have had during transportation. Receipt Inspection – The rotor was visually inspected and electrically checked. There was no evidence of any adverse affects. Detailed inspection report not included in this summary. End Cap Removal – The centralizing ring was packed with dry ice one hour prior to starting the heating process. The induction coils were placed at the nose of the exciter end cap, the cap was heated for approximately one hour to a temperature of 285°C, at which point the snap rings were closed and the cap pushed off the shrink using hydraulic jacks. The induction pipes were transferred to the back of the end cap and a temperature of 220°C recorded, at which point the cap was jacked off the centralizing ring. The same format was repeated for the removal of the turbine end cap although the nose temperature of the cap only attained 260°C at the time of removal. Polishing of End Caps – An attempt was made to remove the varnish utilizing aluminum oxide abrasive cloth on the vertical boring machine. This was partially successful, but it was decided to use an approved paint remover which Parsons utilize on our own end caps. After removing the paint, the caps

Lingan Unit 4
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Background and Description (continued):
1996 (cont'd) - were thoroughly washed down with an electrical cleaner. The caps were polished on a V.T.B. using the aluminum oxide cloth. End Cap NDE - Parsons normal method of NDE on end caps, using liquid fluorescent dye penetrant, was carried out and the results are documented on Hodgson's Inspection Report. Ultrasonic testing of the end caps was also attempted, but this proved to be an inconclusive method of testing. A
Metallographic Examination of the retaining rings was also carried out and the test results are given in the attached Galt Testing Laboratories Ltd. Report. Refurbishment -
Some balance ring packings were broken and others cracked. A full set of replacement balance ring packings were manufactured and installed. The nomex portions of the end winding insulation cylinders were creased and torn. The torn Nomex was separated from the glass portions and new nomex was fitted. Reassembly - Bore gauges were used to check the shrink fits on the nose and rear portions of the end caps. The caps were heated for (4) hours, prior to assembly. No problems were encountered during assembly. After cooling, the cap surfaces were polished and a white heat resistant epoxy enamel was paint applied to protect the end cap surfaces. Standard End Cap Clearance – No issues noted. UT per procedure CL –MG07AA. No defect indications were found. PT per Parsons procedure NDT 42. No unacceptable defects were noted. Six replications were taken from various locations on the E.E end cap. The locations examined were free from stress corrosion cracking and there was no evidence of massive non-metallic inclusions or dense inclusion clusters. Retaining rings inspected by Ultrasonic and Liquid Penetrant. This examination was carried out at Parsons St. Catharine's Plant from May 28 - 31, 1996. Penetrant test - No Unacceptable Defects were noted. Very minor, very well scattered pin-point indications were noted on the shrink face and outboard vertical face of the E.E. Retaining Ring. Examination of an end cap from the exciter end of the Lingan Unit 4 generator was conducted on-site at
Parsons Turbine Canada Ltd. in St. Catharine's on the 30th day of May 1996. Six locations were ground and polished then etched in a 10% nital solution (10% nitric acid in methanol) for metallographic examination and replication. Microscopic examination took place on-site and analysis of the replicas occurred at Galt Testing Laboratories in
Cambridge. Test Results – there were 6 identified areas that were polished, ground and evaluated. No stress corrosion cracking was observed in any area. The microstructure is noted to be austenitic. Photomicrograph of location #4 shows a typical microstructure of twinned austenite grains. As in the five other locations, there was no evidence of stress corrosion cracking. Non-metallic inclusions were widely dispersed. Conclusion -
The locations examined on the end cap were free from stress corrosion cracking. There was no evidence of massive non-metallic inclusion or dense inclusion clusters. Some rust on the rotor was noted. Past hydrogen coolers leaks reported.

2008 - Retaining rings had PT and UT inspection by Reinhard and Assoc. Specific results were not available for review.

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Lingan Unit 4
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Background and Description (continued):
2010 - Plant Interview - Generator Retaining Rings – rings are non-magnetic 18.5 material. PT inspections reported to be done in past. Rings reported to not been off rotor in past.

Preliminary Causes:

- Rings are known to be 18Mn5Cr material, proven to be susceptible to stress corrosion cracking in the presence of moisture and other corrodants. In 1996, six indications in the ring were ground out. These were determined not be stress corrosion cracking. Retaining rings in 2008 were inspected by UT and PT but the report and the results were not available for review by TGA.. In 1996, “rust” was observed when the rotor was at the Parson’s facility. Rust is evidence of moisture.
- A "ring-on" inspection has limitations in its ability to detect stress corrosion cracking on the inner diameter shrink fit areas of the ring. As Kilpatrick states, there have been "cases found where the inside of the ring has been coated with oil, and sound was absorbed, and return reflections from cracks could not be expected." This same paper, as well as other papers indicate that cracks as little as 0.005 inches in length or depth can initiate the start of corrosion cracking that can lead to ring failure. It is very difficult for UT from the OD with the ring installed to detect crack indications to this small level, especially around the more complicated shrink fit geometry. Yet even at this size, SCC is a concern with this material.

Outage Assessment Plan:

- At next rotor out outage, replace rings with new 18.18 material that is resistant to stress corrosion cracking.

Action Items:

- New 18.18 rings have long lead time for procurement if not in stock. Procure early and reserve if not already done so.

- Maintain high level of hydrogen purity.

- Ensure hydrogen dryers are properly working and desiccant is “recharging.”

- Unmachined spare 18.18 rings are in NSPI stock at Trenton 6. Investigate suitability of these spares across the NSPI fleet. Alternatively, investigate contingency plan for commercial swap with vendors, contractors or other owners.

Investigators: Bill Smalls, Robert MacNeil
Date: June, 2011

NON-CONFIDENTIAL

Request IR-22:

For CI# 43170, please describe NS Power's overall AVR program.

Response IR-22:

Recognizing that AVRs have a finite life (less than the typical planned life of a power plant) and that the components of the installed AVRs were becoming obsolete, NS Power embarked on a planned AVR replacement program. This program has seen the replacement of many of the fleet's AVRs in a controlled fashion, integrated into appropriate outages to optimize outage time.

The replacement program is outlined below:

Replacements previously conducted:

- Tufts Cove G2
- Tufts Cove G3
- Pt. Aconi G1
- Lingan G3
- Pt. Tupper G2
- Burnside G1
- Burnside G2
- Wreck Cove G1
- Wreck Cove G2
- Trenton G5
- Victoria Junction 1
- Victoria Junction 2
- Tusket

2016 Planned Replacements

- Lingan G4

2017 Replacements

- Trenton G6
- Burnside 3

Other Units

- Lingan 1 and Lingan 2: utilizing components made available from LIN3/4 retrofits. Will monitor and consider against planned unit utilization.

- Tufts Cove 1: Will monitor and consider against planned unit utilization.

NON-CONFIDENTIAL

Request IR-23:

For CI# 47657:

(a) Please explain the difference in forecasted amount between this project and CI#40363, LIN3 High Voltage Bushings Refurbishment in 2015.

(b) Please provide documentation for the OEM recommendation of refurbishment of the generator bushings.

Response IR-23:

(a) The forecasted amount for CI 47657 is higher than CI 40363 primarily due to the foreign currency exchange rate with the US dollar. Material and installation contract costs are priced/paid in US dollars and make up the majority cost of the project. When the budget for CI 40363 was developed, the Canadian Dollar was closer to par with the US dollar. The actual cost from CI 40363 was used to create the forecast for CI 47657 with the addition of the exchange rate.

(b) Please refer to Attachment 1.

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LST−GEI−XXXX−0007 Rev.2

Major Generator Outage Recommendation

Gen Parts	Inspection Item		Necessary Condition	Interval for Preventive Maintenance	Reference Document	Purpose	Necessary Days
Rotor	1. General Inspection	1) Checking the generator field coil ends 2) Checking the rotor connection lead insulation 3) Checking the field coils and joints for insulation 4) Checking the field coil cooling ventilation holes(Direct Hydrogen−Cooled Type)	Rotor Withdraw	Every Major Outage	Item 1)−4) Inspection of Generator Field Coil CL−MG02A(RE−23)	The generator rotor runs at high speed. The field coils and their insulations are subject to the effect of centrifugal force generated by rotation. The rotor coil is very important parts, therefore, periodical maintenance is necessary.	
	2. Non Ddestructive Test (First Step)	1) Magnetic Particle Test(MT) and Ultrasonic Test(UT) of shaft journal 2) UT of rotor wedge 3) UT and dye penetrant test(PT) from the external circumferences of retaining ring 4) UT of shaft teeth 5) MT or PT of lead wedges 6) PT of fan blade 7) MT or PT of Major bolts	Rotor Withdraw	Every Major Outage	Item 1)−7) Non−Destructive Examination of Turbine Generator Rotor TTIL−KC194501	The shaft, retaining rings, rotor wedges and other major components used in generator rotor are subject to frequent start and stops, and are sometime appeared the fatigue cracks on rotor wedges, fretting fatigue cracks on the slot teeth, and stress corrosion cracks on the retaining rings. It is increasingly important to maintain the high reliability of generator in recent years that these defects are detected and evaluated in detail during the outage.	
	3. Non Destructive Test (Second Step)	**1) MT and UT of shaft center bore 2) MT and UT of shaft journal 3) PT, MT and UT of rotor wedge 4) PT and UT of retaining ring 5) PT and UT of coupling 6) MT of shaft teeth 7) MT of fan bosses 8) MT or PT of lead wedge 9) PT of fan blade 10)MT or PT of majour bolts	Rotor Withdraw Remove retaining ring Remove rotor wedge After re−assemble, high speed balance is required. These inspections need to be carried out in the factory.	More than 100,000 hours or 15 years operation	Item 1)−10) Non−Destructive Examination of Turbine Generator Rotor TTIL−KC194501	Same purpose of "2.Non Destructive Test (First Step)". Second step needs high speed balance of rotor. Therefore, the rotor needs to send to factory which has a high speed balance facilities.	
	4. Others	**1) Inspection of Copper Particle of Generator Rotor Windings **2) Replacement of Retaining Ring to 18Mn−18Cr (In case of 18Mn−5Cr) **3) Change the Distance Block Type to Pop Rivets Type	Rotor Withdraw After these work, high speed balance is required.	Item 1) Total turning time:more than 10000 hours Item 2) As soon as possible Item 3) More than 100,000 hours or 15 years operation	Item 1) Countermeasure for Copper Particles of Generator Rotor Winding TTIL−KC195501 Item 2) Replacement of Non−Magnetic Generator Retaining Rings TTIL−KC187001E		
	4. Electrical Test	1) Winding Insulation Resistance 2) AC Impedance 3) Pole Balance 4) Recurrent Surge Oscillation 5) Air Gap Flux Probe 6) Bore Pressure Test	See Reference Document.	See Reference Document.	Recommended Electrical Test LST−GEI−XXX−0046	See Reference Document.	

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LST-GEI-XXXX-0007 Rev.2

Major Generator Outage Recommendation

Gen Parts	Inspection Item		Necessary Condition	Interval for Preventive Maintenance	Reference Document - should be submitted to customer	Purpose	Necessary Day
Stator	1. General Inspection	1) Checking Stator Wedges for Tightness 2) Checking Spacers in Core Slot for Slipout 3) Stator Core Check 4) Checking and Replacing Various Kinds of Tightening Hardware for Stator Coil Ends 5) Checking Stator Coil Ends for Sausage Wear 6) Checking Stator Coil Ends if They are not Loose between Themselves 7) Checking Spacer Blocks between Stator Coil Phase Connection Rings 8) Checking Sliding Mechanism of Improved Stator Winding Support	Rotor Withdraw	Every Major Outage	Item 1)-8) For Water Cooled Generator Inspection of Water Cooling Stator Coil MG02B(SE-23A) For H2 Gas Cooled Generator Inspection of Generator Stator Winding Insulation CL-MG02A(SE-21)	Generator long time operation and vibration occur the looseness of stator coil. It is important to maintain the high reliability of generator that the looseness are detected during the outage.	
	2. Diagnostic Test of Generator Stator Winding (Off-Line Monitoring)	1) Polarization Index Test 2) AC leakage current test 3) Dielectric loss angle (tan δ) Test 4) Corona (Partial discharge) Test	Rotor Withdraw IPB Disconnect Water Removing (Water Cooled Stator Coil Type)	First Time: More than 100,000 hours or 15 years operation From Second Times: 4-6 years	The Diagnostic Test of Generator Stator Winding (Off-Line Monitoring) SE-26	These Non Destructive Tests of stator coil insulation are more effective for deterioration about stator bar insulation residual life than high potential test.	
	3. Leak Test for Water Cooled Stator Coil	1) In-Leak Test 2) Pressure Decay Test 3) Vacuum Decay Test 4) Tracer Gas Test	Stator Cooling Water Removing 4)Bearing Bracket Off or Rotor Withdraw	First Time: More than 10 years operation From Second Times: 2 years	Leak Test for Stator Winding of Water Cooled Turbine Generator TTIL-KC295501-B	We had experienced the water leakage from stator winding just before filling H2 gas in the generator. As a result, unit is prolonged starting the commercial operation. To prevent such a prolonging the generator overhaul, it is necessary to conduct the leak tests of stator water cooling system and to confirm the leakage of stator winding just after unit shut down.	
	4. Capacitance Mapping Test of Water Cooled Stator Coil	Capacitance Mapping Test	IPB disconnect Rotor withdraw	First Time: More than 10 years operation From Second Times: 2 years	Capacitance mapping test (by manual) LTR-GEI-XXX-0004	If a leakage occurs at the brazed joint portion between coil strand and clip, it has a possibility that water shall penetrate into the ground-wall insulation. This shall cause the reduction of the dielectric strength on the ground-wall insulation. The purpose of this test is to detect the existing of water in the ground-wall insulation at an early stage for preventing the equipment shutdown.	
	**5. HV Bushing (Porcelain Type)	1) Visual inspection 2) HVB Overhaul 2-1) Gasket replacement of bushing 2-2) Gasket replacement of Terminal Board 3) HVB Replacement	IPB disconnect HVB Disconnect	Item 1) Every Major Outage Item 2) 8 years Operation Item 3) 16-24 years Operation	Inspection of Hydrogen Cooled Generator High Voltage Bushing CL-MG02A(SE-17)	Hydrogen leakage have been detected from gasket part of some high voltage bushing franges which was operated more than eight years operation. It is important to do overhaul or replace the bushing before hydrogen leakage occur.	
	6. Sealing Gland Packing	1) Re-tighten the bolt 2) Replacement of the packing	----	Item 1) Every Outage Item 2) 15 years operation	Inspection of Hydrogen Sealing Gland Packing CL-MG02A (SE-22)	The purpose of this letter is to describe a recommendation on the inspection and replacement that should be made to the hydrogen sealing gland packing for drawing out the leads of internal temperature measuring element from the generator stator frame during its scheduled outage period.	
	7. Stand off Insulator	Visual Inspection	----	Every Major Outage	For Water Cooled Generator Inspection of Generator Support Insulator CL-MG02A(SE-25)	Recent checks on the insides of large-capacity water cooled generators revealed some of the generators having wear dust on the support insulators, or their insulator bolts loose or falling.	
	8. Electrical Test	1) RTD Element Resistance 2) RTD Ground Insulation 3) Thermocouple Insulation Resistance 4) Winding Insulation Resistance 5) Insulation Resistance(aka Megger) 6) Over Potential/Hipot 7) Wedge Tightness Map 8) Magnetic Scalar Potential(EL CID) 9) Dynamic Freq. Response	See Reference Document.	See Reference Document.	Recommended Electrical Test LST-GEI-XXX-0046	See Reference Document.	

Major Generator Outage Recommendation

Gen Parts	Inspection Item		Necessary Condition	Interval for Preventive Maintenance	Reference Document - should be submitted to customer	Purpose	Necessary Day
Others	1. General Inspection for Other Parts Except for Rotor, Stator and Excitation Parts	1) Bearing Metal Inspection Visual inspection and penetrant test 2) Seal Casing Inspection Visual inspection and penetrant test of spring 3) Seal Ring Inspection Visual inspection and penetrant test 4) Cooler Inspection 4-1) Cleaning of cooling tube, water box, cooling fin 4-2) Fin slant check 4-3) Gasket replacement 4-4) Water box inner painting 4-5) Sacrificial anode replacement 4-6) Check and repair of leaking cooling tube 4-7) Internal inspection by bore scope 4-8) Thickness inspection by eddy current test	Item 1)-3) Bearing cap disassemble Item 4) Cooler remove	Item 1) More than 400 times start up or Every Major Outage Item 2)-4) Every Major Outage	Item 1) Inspection of Bearing Metal 4GEI00018 Item 4) Inspection of Cooler 4GEI00017 Item 4) Instruction Manual for Hydrogen Gas Cooler SLE10085 Item 4) Instruction Manual for Air Cooler SLE10089	---	
	2. Leakage Check of Hydrogen Gas	H2 Gas Leak Test Assumed Leakage Point 1) HV Bushing 2) Hydrogen Sealing Gland Packing 3) Seal Casing Attaching Face 4) Interior Face of Seal Ring 5) Joint and Attaching Face of the Outer End Shield 6) H2 Gas Cooler Attaching Portion 7) Rotor Terminal Lead Portion 8) Piping	----	Every Six to Twelve Monthes	1	---	
	3. Inspection for Excitation Parts	1) AC Exciter Inspection 1-1) Appearance inspection of rotary rectifier equipment 1-2) Inspection for blown fuse 1-3) Inspection for short circuited rectifier 1-4) Inspection for resitor 1-5) Inspection of leak current for rectifier 1-6) Continuity inspection of capacity 1-7) Degradation inspection of capacitor 2) Static Excitation Inspection 2-1) Visual inspection of collector rings, brushes and brush holders 2-2) Examination of each brush holder for wear 2-3) Replacement of any worn constant-pressure springs 2-4) Tightness check of clamps and bolts 2-5) Cleaning of collector rings and brush holders 2-6) Grinding of collector rings (if necessary) 2-7) Filter inspection and recycling 2-8) Filter mat replacement	Item 1) Disconnect connection leads of generator field winding Item 2) ---	Item 1) Every Major Outage Item 2-1) Daily Item 2-2)-2-8) Every Major Outage	Item 1) Inspection and Maintenance of Brushless Exciter and PMG EKC002644 Item 2-1)-2-6) Inspection and Maintenance of Collector Rings, Brushes and Brush Holder EKC002316 Item 2-7)-2-8) Maintenance of Air Filter EKC002317 Note) These manuals are for sample. Doc. No. of actual manual for each plant is shown in "North America Generator Drawing and Instruction Manual List" LST-GEI-XXX-0014 for INTERNAL (ReGENco/TIC/TSB) USE ONLY.	---	

CONFIDENTIAL (Attachment Only)

Request IR-24:

For CI# 46298:

(a) Was an EAM analysis conducted for this project? If not, why not?

(b) Please describe the overall "general dam safety program" and the timeline of any projects that will be implemented in this program.

(c) Please provide the 2009 Dam Safety Review that concluded the dam requires refurbishment related to concrete degradation and stability concerns with ice loading.

Response IR-24:

(a) As hydro dam safety projects are safety-related capital projects, no EAM was completed.

(b) NS Power's Dam Safety Management Program follows the Dam Safety Guidelines issued by the Canadian Dam Association (CDA). The main components of the program include the following:

- Dam Safety Reviews and Flood Studies
- Emergency Preparedness Plans
- Operation, Maintenance & Surveillance Manuals
- Semi-Annual Dam Inspections

Dam Safety Reviews (DSR) and Flood Studies are undertaken for each of the 17 hydro systems on a 7 year cycle. Typically, two to three DSRs are completed each year and a full set of DSRs, for all 17 hydro systems, are also completed within a seven year cycle.

Emergency Preparedness Plans are updated each year for each of the hydro systems. The updates typically include; changes/refurbishments to the hydro system, contact personnel changes, etc.

NS Power operations personnel conduct semi-annual dam safety inspection in the spring and fall of each year. The goal of these inspections is to identify and note any changes to the water-retaining structures and to identify deficiencies that will require repairs or preventative maintenance. Photographs are also taken during each inspection for documentation purposes.

NS Power also has an established inventory database, which describes all of the water-retaining structures and is used as part of the dam safety prioritization worksheet that categorizes the condition of the structures based on the Dam Safety Reviews. The prioritization worksheet is used as a planning tool to prioritize the structures in terms of their overall condition (stability, freeboard, general condition, etc.) and the results are used to develop the rehabilitation schedule for the structures.

Dam safety related refurbishment projects are prioritized and selected based on the results of the dam safety management program. Each year, the dam safety prioritization worksheet and supporting documentation is assessed to determine which refurbishment projects will be advanced to preliminary engineering assessment and design. Once a project is selected, the preliminary engineering is typically completed over a one to two year period depending on the size and complexity of the project. Large, more complex projects may take longer to complete the preliminary engineering.

(c) Please refer to Confidential Attachment 1.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

SBA IR-24 Attachment 1 has been removed due to confidentiality.

Request IR-25:

Please describe NS Power's dam safety project prioritization. Include methodology, factors taken into consideration, and list of safety projects by prioritization and associated cost estimates.

Response IR-25:

NS Power's dam safety prioritization worksheet is utilized as a planning tool for assessing and prioritizing deficiencies associated with the water-retaining structures (dams, spillways, etc.). The information utilized in the prioritization worksheet is taken from the Dam Safety Reviews (DSR), which are completed for each of the 17 hydro systems. DSRs are complete on a seven year cycle for hydro system and a full set of DSRs, for all 17 hydro systems, are also completed within a seven year cycle.

The prioritization worksheet assesses the structures based on four assessment categories:

(1) Design Adequacy Assessment for a Sunny Day Condition;
(2) Design Adequacy Assessment for an Earthquake Condition;
(3) Design Adequacy Assessment for a Flood Condition; and
(4) General Physical Condition Assessment.

For each category, concern ratings are assigned to each of the items assessed. The maximum of the concern ratings are then assigned as the overall concern rating for the specific structures. The overall concern rating is then multiplied by a scaling factor to determine the Vulnerability Index for each structure.

For a Sunny Day Condition, the reservoir level would be at the Full Supply Level (FSL) or Normal Operating Level. The following items are reviewed as part of this assessment: overtopping of the crest, overtopping of the core, stability of the concrete or timber structures for

No Ice and Ice loading conditions, the downstream slope stability of the embankment structures, and the upstream slope stability based on a rapid drawdown scenario.

For the Earthquake Condition, the reservoir level would remain at the FSL and seismic coefficients would be applied to the analyses. The following items are reviewed as part of this assessment: the stability of the concrete or timber structures under seismic loads, and the upstream and downstream slope stability of the embankment structures under seismic loads.

For the Flood Condition, the reservoir level would be at the Inflow Design Flood (IDF) level, which is the design flood level based on the dam classification of the structure. The following items are reviewed as part of this assessment: overtopping of the crest, overtopping of the core, and the stability of the concrete or timber structures under flood loading conditions.

For the Physical Condition Assessment, the physical conditions of the structures are assessed for the embankment, concrete, and timber structures. The items assessed as part of the embankment structures include: the crest, upstream slope, downstream slope, instrumentation/monitoring, and conduits. The items assessed as part of the concrete structures include: crest/upstream face/downstream face, piers/abutments, gates/stoplogs, apron/foundation, and channel. The items assessed as part of the timber structures include: crest/decking, upstream and downstream faces, abutments, foundation, and outlet channel.

As part of the requirements of the flood studies, risk values associated with downstream flood events are determined based on the design flood scenarios. These values are assessed for both the sunny day failure and flood failure scenarios.

The Vulnerability Index and risk value parameters are used to determine the Risk and Rank scores for each of the four assessment categories. The risk value parameters are used to determine the Life Safety score. The Risk scores are then determined by multiplying the Vulnerability Index by the Life Score for three risk categories: Life Safety Risk, Environmental and Cultural Risk, and Infrastructure and Economic Risk. The sum of the Risk scores, for the four assessment categories, is used to determine the overall risk number of the structure. The overall risk numbers are then sorted in descending order to prioritize the structures. The higher the overall risk number, the higher the rank number.

The prioritization worksheet is a working document and will be updated following the completion of DSRs. The overall prioritization of the structures will change over time based on structures being refurbished, changes to the hydro systems, changes to the CDA Guidelines, etc. The structures are listed, by priority, in the prioritization worksheet and projects are selected based on that information. However, there are no costs associated with each structure/potential project at this time. Potential Preliminary Engineering (PE) projects are identified using the prioritization worksheet and the costs estimates would be completed as part of the PE projects.

For a list of safety projects by prioritization and associated cost estimates, please refer to Attachment 1.

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Capital Dam Safety Projects - Prioritization List (2016 to 2018)

Structures	Prioritization Rank	Deficiencies	Estimated Construction Costs	Potential Rehabilitation Activities
2016 Construction Projects				
Five Mile Lake Dam / Mack Lake Dam Refurbishment	7 / 17	Stability requirements not met. Five Mile Lake Dam in poor physical condition.	$2M	Construct new spillway and sluice gate structures and address stability issues with existing dam by placing rockfill on the downstream side.
WRC Dam D-4 Refurbishment	22	Freeboard and downstream slope stability requirement not met.	$1.5M	Raise the crest and construct a toe berm at the downstream toe.
Nictaux Powerhouse Dam Reconstruction	Not Noted*	Stability requirements not met. Concrete in poor physical condition.	$1.7M	Reconstruct a concrete dam with sluice gate immediately downstream of the existing structure.
Hollow Bridge Canal Dyke Refurbishment	89	Embankment stability requirements not met. Spillway structure in poor physical condition, stability requirements not met.	$4.3M	Construct toe berms along the downstream toe areas of the embankment sections, construct a new spillway structure, extend the spillway channel, construct a new intake gate at the entrance to the canal, and install a new gate in the intake structure.
2017 Construction Projects				
Marshall Falls Dam Refurbishment	10	Embankment stability requirements not met. Spillway structure in poor physical condition, stability requirements not met.	$3.5M	Refurbish the embankment dams and construct a new spillway/ sluiceway structure.
Scragg Lake Dam Refurbishment	14	Embankment stability requirements not met. Spillway structure in poor physical condition, stability requirements not met.	$0.75M	Reconstruct the spillway/sluiceway structure and upgrade the embankment sections.
WRC Dam D-9 Refurbishment	21	Freeboard and downstream slope stability requirement not met.	$1.5M	Raise the crest and address slope stability concerns.
Tusket Main Dam/Canal Embankment/Powerhoue Dam Refurbishment	45/30/31	Freeboard and stability requirements not met. Operational deficiencies with the tainter gates in winter conditions.	$7.7M	Construct a new concrete dam structure, construct a new bridge downstream of the dam, and refurbish the embankment dams.
Lequille Headpond Dams & Spillways Refurbishment	43	Freeboard requirements not met for all water-retaining structures.	$3.5M	Increase the discharge capacity of the spillway structure, raise the embankment dams, and refurbish or replace the canal intake structure.
Ruth Falls Dam Refurbishment	56	Freeboard and stability requirements not met. Operational deficiencies exist with the stoplog structure.	$4M	Refurbish the concrete dam and embankment structures.
2018 Construction Projects				
Sissiboo Falls Dam	29	Rubber dam requires replacement, possible concrete work required.	$2.5M	Replacement of the rubber dam and possible concrete works.
Gulch Spillway (Possible)	66	Stability requirements not met. Concrete in poor physical condition.	$2.5M	Refurbishment of the concrete spillway.
WRC Dams D-5, D-6-1 and D-6-2	148/76/148	Freeboard and downstream slope stability requirements not met. Major seepage issues and high pore pressures at Dam D-6-1.	$4M (combined)	Raising of the dam crests and addressing the slope stability concerns. Also, addressing the high seepage flows in Dam D-6-1.

* - The Nictaux Powerhouse Dam was not previously noted in the dam safety prioritization worksheet and was included following the results of the 2012 Dam Safety Review of the Nictaux Hydro System.

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Request IR-26:

For CI# 47397:

(a) Was an EAM analysis conducted for this project? If not, why not?

(b) Please provide the 2010 Dam Safety Review that concluded Dam D-4 did not meet the stability requirements for the steady state seepage condition on the downstream slope and did not meet the Normal or Minimum Freeboard requirements.

(c) When were the new CDA guidelines for minimum freeboard instituted? At what date did Gisborne violate the CDA guidelines?

Response IR-26:

(a) As hydro dam safety projects are safety-related capital projects, no EAM was completed.

(b) Please refer to Confidential Attachment 1.

(c) The latest version of the CDA Guidelines was issued in 2007. The Minimum Freeboard deficiency for the Gisborne Dam D-4 was identified in 2001 as part of a Flood Study Review (Amec, 2001). Consistent with all Dam Safety projects, these are prioritized on an annual basis to determine which Dam Safety projects require completion.

SBA IR-26 Attachment 1 has been removed due to confidentiality.

Request IR-27:

For CI# 47396:

(a) Was an EAM analysis conducted for this project? If not, why not?

(b) Please provide the 2012 Dam Safety Review that concluded Nictaux Powerhouse Dam was in poor condition with significant concrete deterioration and cracking and did not meet the stability requirements for the usual ice and flood loading conditions.

(c) Why was the Nictaux Powerhouse not classified as part of the 2010 Flood Study?

(d) Please explain and provide any supporting documentation that justifies the Nictaux Powerhouse Dam being classified as "Low" in the 2012 DSR analyses.

(e) Please provide any analysis showing alternatives, such as constructing a smaller concrete dam with rock anchors, considered. Please provide any supporting documentation showing that the alternatives considered are less desirable.

Response IR-27:

(a) As hydro dam safety projects are safety-related capital projects, no EAM was completed.

(b) Please refer to Confidential Attachment 1.

(c) The dam was not classified as part of the 2010 Flood Study as the dam is a low height structure with the resulting downstream impacts deemed to be low in the event of a dam breach.

(d) The dam was conservatively classified as Low in the 2012 DSR analysis. In assigning a Low classification for the analysis, the loads applied on the structure would be the lowest recommended design loads. If the structure passed the stability requirements with the lowest recommended design loads, then the dam classification would have been increased until the design loads were not met. In the case of the Powerhouse Dam, the stability criteria were not met for the lowest recommended design loads thus increasing the design loads was not required. In addition, the dam is a low height structure and downstream impacts would be limited in the event of a dam breach.

(e) The design alternative to have a smaller concrete dam with rock anchors was cost comparable to the selected simple concrete gravity dam option. The simple concrete gravity dam option would be less complicated to construct, have a safer installation process, and would be less likely to run into field issues. The use of rock anchors would inherently include design life and long-term performance concerns. The concrete gravity dam option without rock anchors eliminates the design life and performance concerns.

SBA IR-27 Attachment 1 has been removed due to confidentiality.

NON-CONFIDENTIAL

Request IR-28:

For CI#48018, was an EAM analysis conducted for this project? If not, why not?

Response IR-28:

No, an EAM was not completed for this project. Tuft's Cove Generation Station is now operated more for capacity purposes than for general energy production purposes. This is similar to how projects associated with the gas turbine units are justified. In order to reliably operate the unit, this work must be completed. The alternative would be to invest in additional new generation to replace the generation from Tuft's Cove. This is not considered a viable option at this time due to the high cost of new generation as compared to the cost of continued operation of Tufts Cove Unit #1.

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Request IR-29:

For CI# 47611:

(a) Was an EAM analysis conducted for this project? If not, why not?

(b) Please detail the ongoing maintenance costs associated with Pt Tupper Unit 1 since its retirement.

(c) Please provide a summary of all future on-going costs associated with Pt. Tupper Unit 1.

Response IR-29:

(a) No. This project is justified based on safety; therefore, an EAM analysis was not completed for this project.

(b) The ongoing maintenance costs for Unit 1 stack have been inspection and maintenance costs in order to comply with Thermal Maintenance Practice – 03 Stack Inspection. Inspection costs are approximately $5,000 annually, and repair costs vary year over year, with the most recent cost being the installation of mesh material to mitigate the risk of falling bricks at an approximate cost of $5,000.

(c) Once the stack is removed in 2016, the only cost anticipated is related to the removal of Galbestos siding.

Request IR-30:

For CI# 47172:

(a) Please provide the 2014 condition assessment report which determined that the runner and wicket gates are experiencing significant cavitation and the rotor requires additional assessment.

(b) What is the long-term operating strategy of Tidewater Unit #1?

Response IR-30:

(a) Please refer to Attachment 1.

(b) Tidewater Unit #1 is a run of river machine that is expected to be operated well into the future. No changes to its operating strategy are expected.

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NSP-27T HYDRO UNIT INSPECTION CRITERIA

PLANT: Tide water
UNIT #: 1

DATE: 14 August 2014
CREW: G. McLeod / A. Hamm
WORK ORDER: 66223

INSPECTION COMPONENT	RATING	COMMENTS/OBSERVATIONS
PRE-SHUTDOWN (as exercise before inspection)		**Note: Inspection Criteria is to be used in addition to PM checklists as well as the Overhaul Parts Inspection Checklist**
Bearing temperature	1	no problems with overheating.
Thermal Scan	N/A	
Excessive leakage (oil, air, water)	2	Some minor oil leakage.
Vibration analysis	5	Not working.
Oil Analysis	1	awaiting testing.
OPERATIONAL ISSUES:		
Shutdown	1	no issues, do not need to close main valve.
Hot spots (windings)	1	unknown, no known issues.
Probes not working	1	Working, just old style.
Adequate oil systems/flows	1	Good.
Runner Condition		
Condition of Runner - Cavitation	4	major cavitation on backside of blades (top)
Excessive Clearance in Runner Seals	1	good.
Blade Cracking	4	Nothing visible, but possible due to
		the major cavitation.
KAPLAN:		
Check for oil in water	N/A	
Check for water in oil	N/A	
FRANCIS:		
OK		
Alignment of runner in seals	1	good.

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FIXED/PROPELLER:		
Check for cracks in blades	3	not able to check, nothing visible, but will crack due to major cavitation
Throat Ring / Draft Tube Condition	/	Unable to evaluate this area.
Cavitation		
Liner Deterioration (filler)		
Cracking		
Concrete Deterioration		
Separation of liner and concrete		
Condition of anodes		
STAY VANES		
Check for cracking	1	good.
Check for condition of paint	2	requires cleaning / painting
PENSTOCK		
Concrete condition (cracking, leaking, spawling)	1	Pipeline / butterfly valve.
Condition of drain	1	good
Check condition of screens for water intake	1	cleaned.
Check for sealing of headgates	1	slight leakage
Condition of manhole cover and studs, and lifting attachments	1	OK, replace studs during next overhaul
SCROLLCASE		
Condition of coating	2	needs to be cleaned and recoated.
Condition of rivets	1	look OK.
Check for leaks	1	none

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HEADCOVER/SEAL CONDITION		
Upper & Lower Seal Condition Wear	1	look ok according to clearances.
Gate Link Bushing Wear	2	show signs of wear
Eccentric pin and gate link pin wear	2	show signs of wear
Push Pull Rod Bushing Clearance	2	show signs of wear
Operating Ring Bushing Wear	2	show signs of wear
Cavitation on Wicket Gates	3	a lot of scale, should be ND Tested for thickness.
Wicket Gate Clearance	1	OK, difficult to get good clearances top/bottom (excessive scale)
Paint condition	2	No paint on gates; no paint on headcover
Water leaks	2	water on headcover, unknown source.
Packing glands Wicket Gates	2	none adjustable packing on wicket gates.
Vacuum valves	1	good.
Condition of deck plates	N/A	Has no deck plates.
QUADRANT SHAFT:	N/A	N/A
Bearings		
pins		
bushings		
Connecting rod for quad/terminal shaft		
TERMINAL SHAFT		
bearings	2	some play

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GREASE LINES	2	no remote grease lines.
TURBINE SHAFT		
Turbine Water Seal Wear (Carbon, Labyrinth, Packing)	2	Packing, OK
Excessive Run Out	1	No, .006"-.008"
Vibration / Bearing	5	Unknown, vibration monitors not working
Turbine bearing supply piping	1	S/S piping.
PIPING AND TUBING		
Oil Leaks	3	minor oil leaks on bearing pots and governor.
Type of material	1	steel / brass / stainless.
ORRA Status/Condition Assessment	2	cooling water flow meters installed, nothing else done for ORRA.
GENERATOR		
Static Air Gap (Pilot)	N/A	
Winding Cleanliness	2	dirty
Rotor Shaft - Excessive Runout (upper)	1	good
Rotor Shaft - Excessive Runout (lower)	1	good.
Rotor Pole Cleanliness	3	dirty, flaking paint
Collector Ring Wear	1	minor wear
Collector Ring Cleanliness	2	dirty
Vibration	5	Good, but not vibration monitor working.
Exciter Housing Condition	1	carbon dust.
Commutator Wear	1	some wear, refurbish during overhaul
Temperature probes	1	all working, old style
Braking surface	1	smooth
Brake pads wear	1	3/4" of pad left - (usable)
EXCITER		
	1	dirty, carbon dust
GENERAL		
Hand rails, deck plating, access ways	1	good.

NSPI HYDRO UNIT MASTER LIST

Date Revised: (02-Dec-2010)

SYSTEM: HES PLANT: St Margarets Bay UNIT: TW1 Revised By: Robert Lord

SECTION 1: GENERATOR

Manufactured By:	Can. Gen. Elec.	CFS:	Approx. 300	Number of Rotor Poles:	24	
Year:	1921	Horsepower:	3450	RPM:	300	
PMG		Stator Weight:		Weight:	App. 40,000	
Pilot Exciter	NA	Main Exciter:	Yes	Collector Rings	Yes	
# of Brushes	NA	# of Brushes	24	# of Brushes	12	
Brush Data:	NA	Brush Data:	EG6345	Brush Data:	EG6345	*AY BI , AYMI , AYLI

SECTION 2: SHAFT DATA

Flange OD:		Bolt Diameter / OD:		Torque Values per Flange:	
Length		# of Bolts per Flange:		Coupling:	
Shaft OD:		Bolt Length:		Fitted:	
# of Sections:	2			Tapered:	
Individual Weights:				OEM:	
Total Weight:					

SECTION 3: BEARINGS

TURBINE:		LOWER GUIDE:		UPPER GUIDE:		THRUST:	
Type of Seal:	Packing Teflon	ID:		ID:		ID:	
Type of Oil:		Type of Oil:	Tresso 68	Type of Oil:	Tresso 68	Type of Oil:	Tresso 68
Quantity of Oil:		Quantity of Oil:		Quantity of Oil:		Quantity of Oil:	
Last Test Date (Oil):		Last Test Date (Oil):		Last Test Date (Oil):	?	Last Test Date (Oil):	?
Cooling Coil (Internal or External)	NA	Cooling Coil (Internal or External)	NA	Cooling Coil (Internal or External)	Internal	Cooling Coil (Internal or External)	Internal
# of Coils:	NA	# of Coils:	NA	# of Coils:		# of Coils:	
Tubing Type:	NA	Tubing Type:	NA	Tubing Type:		Tubing Type:	
Tubing Size:	NA	Tubing Size:	NA	Tubing Size:		Tubing Size:	
Tubing Length:	NA	Tubing Length:	NA	Tubing Length:		Tubing Length:	
ID:	NA	Shaft - OD Diameter:	NA	Shaft - OD Diameter:		Shaft - OD Diameter:	
OD:	NA					Thrust Block Height:	
Shaft Sleeve:	NA					Thrust Block Weight:	
Length:	NA					Thrust Block OD Diameter:	
						Spring Bed	
Thickness:	NA	Bearing Journal Size:		Bearing Journal Size:		# of Pads:	
Bearing Casing OD:		Height:		Height:		# of Springs:	
Bearing Casing Height:		Bearing Pot Weight:		Bearing Pot Weight:		Torque on Springs:	
Lined with Babbit, Plastic or Wood:		Babbit Lined:	Y/N	Babbit Lined:		Babbit Lined:	
Last Re-lined:		*Last Re-lined:*		*Last Re-lined:*		*Last Re-lined:*	
Lube Pump		Lube Pump	Yes - on	Lube Pump	No	Lube Pump	No
Motor Size:		Motor Size:	Shaft in sump	Motor Size:		Motor Size:	
Motor Capacity:		Motor Capacity:		Motor Capacity:		Motor Capacity:	

SECTION 4: HEADCOVER

# of Wicket Gates:	20	Coated or Painted		# of Sheer Pins:	20 Links	# of Eccentric Pins:	20 (?)
Last Repaired:	?	Coating Material:		Tapered:	Y/N	Eccentric Pins Offset:	
Spares in Stock:		Date Coated:		OD:		Length:	
Fits Other Units?	Y/N	Last Sample Material:		Length:		Material:	
Gate Weight:		Sample Report # :		Material:			
Gate Width:	Y/N	*Repair Date:*		Nut Thread OD:			
Gate Height:	Y/N	*Report # :*		Thread Pitch:			
Gate Material:		Welding Repairs:	Y/N	Nut Size:			
Bottom Ring Bushings New:	Y/N	OEM Gate:	Y/N	Number of Nuts:			
Off Set:	Y/N	*Replacement Date:*					
		Report # :					
Upper Stem (gate) OD:		Lower Stem OD:		*Last Headcover Repair:*			
Bushing ID:		Bushing ID:		*Type of Repair:*			
Last Bushing Install:		Last Bushing Install:					
Size: OD		Size: OD		Operating Ring End OD:		Push/Pull Rods:	
ID:		ID:		ID:		Length Overall:	

NSPI HYDRO UNIT MASTER LIST						Date Revised: (02-Dec-2010)	
SYSTEM: HES		PLANT: St Margarets Bay		UNIT: TW1		Revised By:	Robert Lord
Bushing Height:		Bushing Height:		Height:		Pin Diameter OD:	
Bushing Material:		Bushing Material:		Ring Guides:	Y/N	Rod End Hole (1) ID:	
Ring Dimensions:				Ring Guide Material:		Rod End Hole (2) ID:	
OD:				Upper Seal ID:		Lower Seal ID:	
ID:				Upper Seal OD:		Lower Seal OD:	
Height:				Seal Material:		Seal Material:	
# of Gate Links:							
SECTION 5: TURBINE:							
Type of Wheel:	Francis	Straight or Non-Fitted Turbine:		Cavitation Repairs:		Date Repaired:	
Number of Blades/Buckets:		Mar. OD of Turbine:		Crack Repair:		Repair/Report Prepared:	
Modified (cut) Date:		*Turbine Replaced:*		Report Identification Number:		CWB Repair Procedure # :	
Blade/Bucket Base Metal Sample # :				Bottom Ring Line Bored:			
NDT Complete:		*NDT Firm Date:*					
NDT Test Date:							
SECTION 6: GOVERNOR:							
Gate Shaft Style:				Cabinet Actuator Style:			
Manufacturer:	Woodward	S/N:		Woodward S/N:		Manufacturer Date:	
Operating Pressure:	200	Piston Diameter:					
		Date Repaired:		*Modifications:*			
		Date Replaced:					
Modifications:							
Oil Volume:		Oil Type:	Tresso 68				
Pump Repairs:	Y/N	Repair Date:					
Copper Lines	Y/N	Schedule Replacement:					
Rod Diameter:	1,996"	Last Overhaul:				Last 5-Year Overhaul:	
"V" Packing Size:		Rep:				Rep:	
"V" Packing P/N:							
SECTION 7: BRAKES				SECTION 8: OTHER			
Number of Brakes:	2						
Oil or Air Brakes:	Oil						
Type of Brake Material:							
Size:							

– new air compressor/drier in plant to be hooked up for air brakes

WO# 00253

Nova Scotia POWER An Emera Company

SYSTEM St. Margaret's Bay Hydro. SHEET No. 1
SUBJECT TIDEWATER UNIT #1
DESIGN CHECKED DATE 13/14 Aug 2014.

Tidewater 1 Condition Assessment by A. Hamm, G. McLeod
This unit turns counter-clockwise.

Draft tube
- tried to inspect with a bore scope, but the shape of the buckets do not allow sufficient room. Looks like a lot of heavy scale.
- recommend getting divers to make a thorough inspection of draft tube and runner area.

Runner
- Francis type runner
- very dirty
- no visible signs of cracking.
- some of the blades must have been hit at some point, see pics.
- very bad cavitation on underside of blades near the top band. Could not get good pictures but made moulds with duct-seal. Every blade is like this. Should have divers do a thorough inspection from draft tube.

Lower Gate Ring
- lower bushings have clearance, checked by prying and showed .020" - .050" movement on dial indicator.

Stay vanes
- in relatively good condition, no cracks.
- not much paint left on them, should be recoated during next overhaul.

Nova Scotia POWER An Emera Company

SYSTEM

SHEET No. 2

SUBJECT Tidewater #1

DESIGN CHECKED DATE

Wicket gates
- heavy scale build up on gates
- gate to gate clearances seem very good.
- sounding the gates with a hammer they seem very thin.
- back side of gates (toward runner) seem to be in better shape that the front face.
- a couple have stainless sealing edge, most are just the casting.
- no paint on gates.
- difficult to obtain top and bottom wicket gate clearances due to heavy build up of scale and rust.

- Scollcase
- very dirty with scum buildup. Paint flakes off of steel very easily, in hand-size pieces.
- The entire scroll case area should be pressure washed, blasted and recoated during overhaul.
- the cooling water intake screen was almost completely plugged. Removed and cleaned. Had to weld studs in place to reinstall screen as the threaded section ripped out of scrollcase when bolts were removed.
- without needle gunning them, the rivets seem to be OK.
- drain hole and drain plug are good, plug has a stem on it for alignment.
- butterfly valve is ok., minor leakage from headgates. Runs off a bull gear.
- Scroll case is very tight on the US side but it is high so you can lay on your side to obtain clearances.

80 40 0170 REV 2011-08

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia POWER An Emera Company

SYSTEM

SUBJECT Tidewater #1

DESIGN

CHECKED

SHEET No. 3

DATE

- Manhole Cover
  - cover is in good condition.
  - studs are ok but should be replaced during an overhaul. Studs are 1⅛x7Tpi, 4 3/4" long

Wheelpit area

- very tight, cannot stand upright to work.
- all concrete walls, no steel liner.
- poor lighting in wheelpit.
- no grease lines, just buttonhead fittings on all pins/links/bushings.
- very tight area for line boring cupling bolts, should be done out of wheelpit.
- no floor plates in wheelpit.
- prior to an overhaul, wheelpit should be pressure washed and vacuumed
- head cover would need to be recoated.
- wicket gate arms sit on a thrust washer, tapered keys drive the gates/arms and there is a double nutted stud that is used to set the gate heights.
- runner shaft is very badly pitted for about 6" above the packing gland, making it difficult to use this area for the level during alignment.
- oil leaks in pit area - lower guide sump has paper gaskets that are saturated with oil and sweating, lower guide sump is leaking at split. Piping from the upper guide/thrust sump is leaking at fitting. Piping that dumps into lower guide bearing through lower bracket is leaking and wrapped with oil soaker pads.

- Push/Pull rods
  - 2 rods, adjustables
  - bushings/pins are worn on both ends.

80 40 0170 REV 2011-08

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia POWER An Emera Company

SYSTEM
SUBJECT Tidewater #1
DESIGN
CHECKED
SHEET No. 4
DATE

- gate links / pins / bushings
  - very difficult to get links off without raising the operating ring.
  - very tight nuts/pins and very tight workspace.
  - did not remove to measure, did a visual on wear in pins/bushings. Measured the spares.
  - some have more clearance than others
  - operating ring shows side shift movement as it rotates.

- Govener - WOODWARD, TYPE HR, № 6115, 16300 Ft/lbs) size 10 x 14.
  - main valve stem is leaking.
  - some leaky piping on govenor.
  - rod size is 1.996"
  - when operating govenor by handwheel, govenor will go to 0 gate and will open to about 3/4" past 100%, shuts down to about 4% hydraulically.
  - no issues with unit stopping.
  - linkages - cross head rocks.
    - top and bottom shafts for crosshead show signs of endplay
    - pin/bushing on terminal gate shaft worn.
    - top hat bearing is worn.

Lower Bracket
- houses the lower guide bearing.
- is completely adjustable for alignment purposes.
- holds the 2 brake calipers.
- brake lines are hydraulic hoses
- brakes are hydraulic not air operated. Should be changed during ORRA.
- brakes have 3/4" of usable pad remaining
- brake band is very smooth.

80 40 0170 REV 2011-08

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia POWER An Emera Company

SYSTEM
SHEET No. 5
SUBJECT Tidewater #1
DESIGN
CHECKED
DATE

Rotor / Stator

- rotor poles and stator windings are coated in oil and carbon dust. Not dripping, just a haze.
- paint is blistered off of rotor poles. Probably due to heat.
- two rotor pole connections, between poles at US and DS, are missing insulation tape, should be repaired.
- Rotor/stator should be dry ice blasted, dried out and painted with approved paint.
- No problems with Meggar.
- Stator has a hold down bolt that is missing (DS/R)
- Stator can be jacked around to centre it during alignment.
- some stator windings are wavy, see pictures.

- Upper bracket (SPIDER)
  - arms are drilled and tapped that can be used for levelling thrust during alignment
  - there is a lot of thin shims under the legs, has layers of mica also for insulation. Shims should be measured and some thicker shims made up during an overhaul.

Slip Rings

- located between upper guide bearing and lower guide bearing.
- have a definate wear pattern from brushes.
- should be refaced during overhaul.
- have some oil on slip rings due to leakage from upper guide bearing pot piping and lower guide bearing misting.

80 40 0170 REV 2011-08

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia POWER An Emera Company

SYSTEM

SUBJECT Tidewatu #1

DESIGN

CHECKED

SHEET No. 6.

DATE

- Exciter
  - fair amount of carbon dust around housing and commutater.
  - commutater has some minor nicks and grooves but overall not too bad. Should refurbish during an overhaul

- ORRA - new compressor is in plant with electronic dryer.
  - all probes are working but are old style. Should be upgraded during overhaul or when they fail.

- vibration monitor system has stopped working, this is a safety issue and should be repaired!

Bearing Temperatures

Thrust — 142°F — Plant temp. 27°C July 2014.

Upper Guide — 120°F — Runout .006"

Lower Guide — 46°C — Output at 40%

Unit Data — Head — 90ft

Hp — 3450

RPM — 300

* Overhead crane is rated at 25 TON but is derated to 3500 lbs. Would need to be repaired/replaced prior to an overhaul.

ALARM CODE =

Nova Scotia POWER An Emera Company

SYSTEM

SUBJECT Tidewater #1

DESIGN

CHECKED

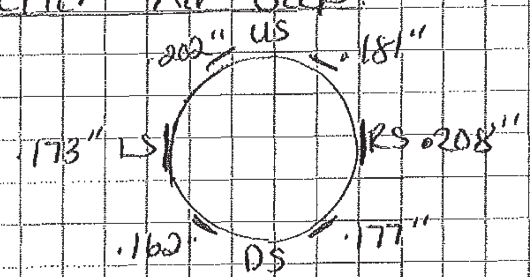
SHEET No. 7

DATE

STATOR AIR GAP

US – .468"
DS – .491"
LS – .501"
RS – .445"

Exciter Air Gap



– checked shaft with level – US/DS is good, seems to be laying a bit to the LS but as noted, shaft is very rough and any irregularity can give false readings. Best place for level during overhaul is the thrust collar.

80 40 0170 REV 2011-08

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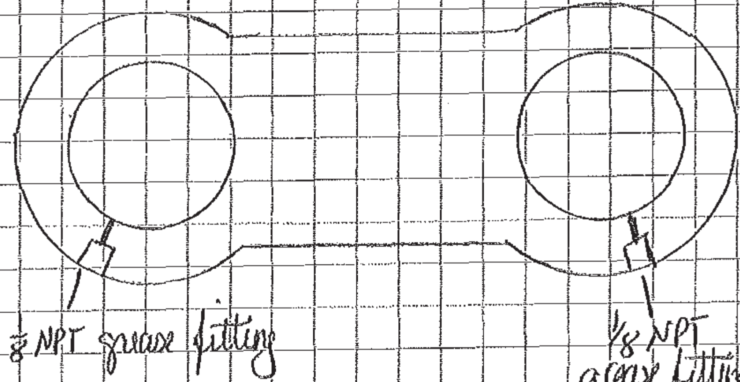
Nova Scotia POWER An Emera Company

SYSTEM ______ SHEET No. 8

SUBJECT Tidewater #1

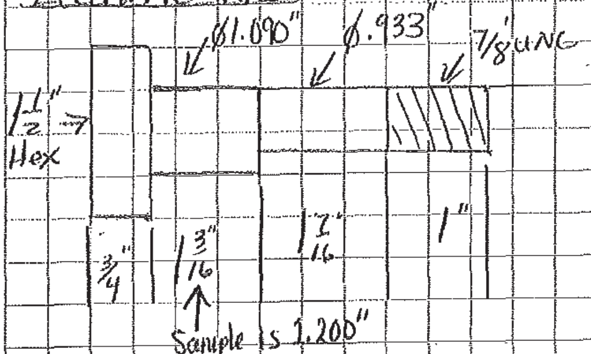
DESIGN ______ CHECKED ______ DATE ______

Gate Links   20 links



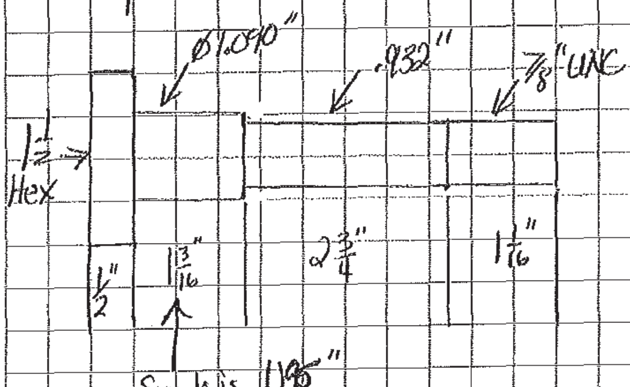
- Diameters of bushings for pins 1.105" } out of 1.110" } round.
- Center to Center of bushing holes is 3.250"

Eccentric Pins.



20 pins.

Straight Pins



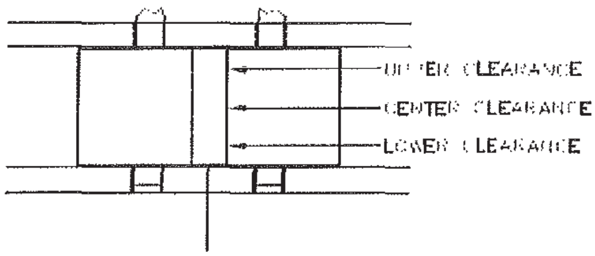
20 pins.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

WICKET GATE VERTICAL CLEARANCES TO GATES, HEEL TO TOE

PLANT TIDEWATER
UNIT # 1 / 92H1-01-02

DATE 13/14 Aug 2016
CREW GH / AH
WORK ORDER 66233



GATE #	UPPER	CENTER	LOWER
1 + 2	.005"	.000"	.000"
2 + 3	.000"	.000"	.000"
3 + 4	.000"	.000"	.021"
4 + 5	.000"	.000"	.000"
5 + 6	.000"	.003"	.012"
6 + 7	.000"	.000"	.000"
7 + 8	.003"	.000"	.040"
8 + 9	.016"	.000"	.009"
9 + 10	.148"	.149"	.153"
10 + 11	.037"	.032"	.038"
11 + 12	.000"	.000"	.004"
12 + 13	.055"	.055"	.082"
13 + 14	.006"	.003"	.000"
14 + 15	.006"	.000"	.000"
15 + 16	.000"	.000"	.010"
16 + 17	.000"	.000"	.004"
17 + 18	.000"	.000"	.004"
18 + 19	.000"	.004"	.000"
19 + 20	.006"	.008"	.008"
20 + 1	.020"	.020"	.020"

* Lower gate bushings have .020"-.050" clearance. Checked with dial indic.

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MEASUREMENT OF WICKET GATE CLEARANCE

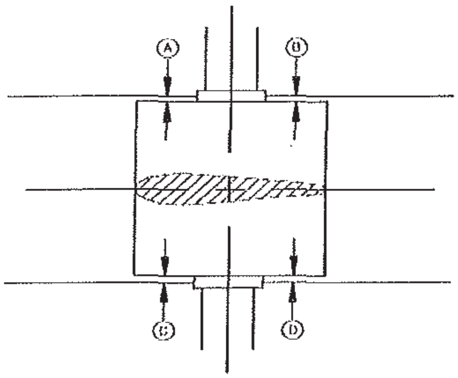
PLANT Tidewater

UNIT # 1

DATE 13/14 Aug 2014

CREW GM / AH

WORK ORDER 66233



Unit = 1/100 mm

GATE #	A	B	C	D
1	.010"	.000"	.009"	.000"
2	.005"	.003"	.015"	.000"
3	.016"	.015"	.027"	.000"
4	.014"	.008"	.010" to .034"	.000"
5	.006"	.006"	.008"	.000"
6	.004"	.004"	.003"	.000"
7	.008"	.008"	.017"	.000"
8	.009"	.003"	.009"	.000"
9	.004"	.000"	.018"	.000"
10	.000"	.000"	.033"	.023"
11	.003"	.000"	.000"	.000"
12	.000"	.000"	.000"	.000"
13	.003"	.004"	.009"	.000"
14	.000"	.000"	.009"	.000"
15	.002"	.000"	.003"	.002"
16	.003"	.002"	.003"	.002"
17	.004"	.003"	.003"	.002"
18	.004"	.003"	.004"	.003"
19	.006"	.000"	.003"	.003"
20	.008"	.008"	.003"	.003"
21				
22				
23				
24				

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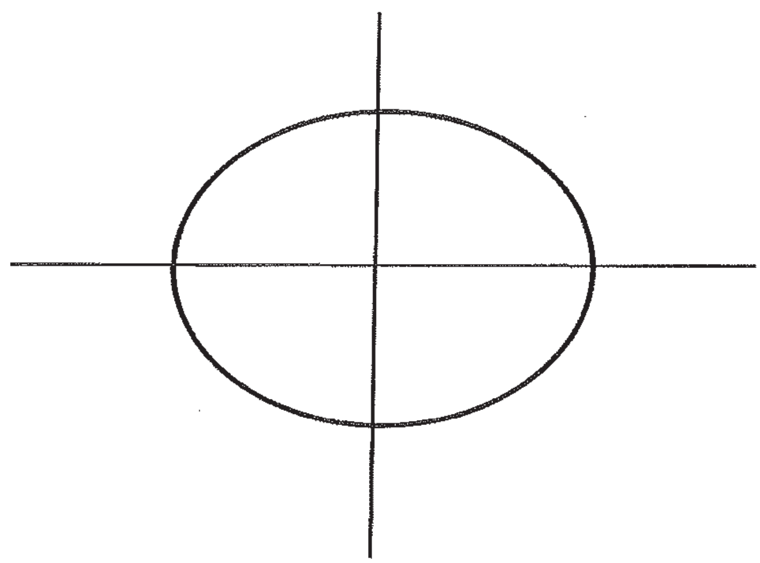
RUNNER SEAL CLEARANCES

PLANT Tidewater
UNIT # 1

DATE 13/14 Aug 2014
CREW GM/AH
WORK ORDER 66233

UPPER		LOWER	
US	.114"	US	.046"
DS	.1025"	DS	.077"
LS	.109"	LS	.054"
RS	.095"	RS	.062"



Request IR-31:

For CI# 47332, please describe the long-term operating strategy of Methals Generating Station.

Response IR-31:

Methals Generating Station is the top unit on the Black River Hydro System. Investments have been made to sustain the operational viability of this hydro system. NS Power expects to operate the hydro assets for the foreseeable future and have no retirement plans.

Request IR-32:

For CI# 47552, please describe and provide any results of the Non-Destructive testing completed during 2015 that led to additional tube replacements and therefore a higher project budget in 2015.

Response IR-32:

Please refer to Attachment 1 for a list of all of the Reheat finish tubes that are currently below minimum wall thickness (0.100”). The tubes being replaced in 2016 were informed by non-destructive testing inspections in 2014 and 2015. All those under 0.095” have been scheduled for replacement. Reheat tubes replacement represents to most significant contribution to project cost increase.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Trenton 5
Jul-15
RH Finish

Plt 7, 8, 9 & 11 are duplicates from 2014

2014

Plt #	Tube #	Point	UT
5	35	2	0.086
6	35	2	0.097
7	32	2	0.097
8	32	2	0.097
8	35	2	0.091
9	32	2	0.098
10	32	2	0.086
10	33	2	0.098
11	32	2	0.099
11	35	2	0.099
12	32	2	0.097
14	32	2	0.092
15	32	2	0.087
19	32	2	0.092
30	32	2	0.095
31	32	2	0.095
31	33	2	0.095

2015

Plt #	Tube #	Point	UT
5	32	2	0.092
7	32	2	0.097
8	32	2	0.095
9	32	2	0.094
9	34	2	0.091
11	32	2 - 3	0.092/.095
16	33	2	0.089
17	33	2	0.095
17	34	2	0.095
18	32	2	0.085
20	32	2	0.089
24	32	2	0.099
29	32	2	0.093
34	32	2	0.095
35	32	2	0.094
36	32	2	0.087
37	32	2	0.097
37	33	2	0.098

23 Tubes to be replaced IN 2016

NON-CONFIDENTIAL

Request IR-33:

For CI# 48018, please provide the health assessment supported by independent industry experts that recommends turbine blades replacement.

Response IR-33:

Please refer to Attachment 1 (excerpt from Tufts Cove Unit 1 TGA Condition Assessment). The 2011 recommendations by TG Advisors call for a contingency plan for numerous rows of blade replacements. Given the age of the unit and higher than planned utilization due to the price of fuel, NS Power technical staff have opted for planned replacement for the rows of highest concern and, will react to other issues as found during inspection.

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Turbine-Generator Health Assessment
Outage Plan Summary

Plant	Unit #	Issue #	Availability Factor	Rating (MW)	Problem Description	Major Outage Assessment Plan and Recommended Corrective Action	Action Items Major Outage	Resp. Engr(s)	Next Major Outage Part/Service Provider	Next Major Outage Estimated Cost ($)	Long Term Contingency Plan Cost ($)	Cap (Y/N)	Last Insp. (Year)	Target Insp. Interval (years)	Comments	Inspection Findings	Date Complete
Tufts Cove	1	HP1	6	100	HP blade cracking, SPE, FOD, and creep damage	• With main steam temperature (1000°F), and unit operation since 1965, the first few HP stages should be inspected for signs of creep such as changes in shroud OD. Rows 1R to 3R replaced in 1999, but should be monitored. • Heavy mid-span rubbing of the rotor may be caused by one of several mechanisms (rotor bow, cylinder humping due to cover/base temperature differentials, water induction, and vibration). Cause should be evaluated particularly if rubbing noted again at next outage. • As a predictive tool, maintain turbine TSI in calibration and monitor unit vibration to detect minor changes in unbalance that may be due to shroud and blade loss.	• Continue to monitor for vibration changes as indicator of blade issues. • Very little data in the reports available for review. Research if any additional information is available and confirm if any other rows replaced besides 1R to 3R in 1999. • Identify and procure a qualified blade repair contractor prior to next major outage. • Develop a pre-outage contingency plan for HP rows in case any of these rows need replaced. Develop a specification for OEM and non-OEM blade vendors to bid on supply and installation either during this outage (if damage requires) or for a future outage. Accommodations for first week onsite outage inspections for suppliers should be made to ensure accurate proposals (after covers are removed). • Incorporate following inspection into outage planning: - MT/PT inspection of rotor and blade surfaces including accessible shaft radii & surfaces, and inlet & outlet end faces of axial fit blade roots (as applicable), blade foils, and under shroud bands (as applicable). - Shroud lift checks (undershroud feeler gage) and tenon UT for all notch	Greg Carlin	Inspect / NDE Row 4 contingency Install		 $100,000 $40,000		2008	2014 2014+			

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Turbine-Generator Health Assessment
Outage Plan Summary

Plant	Unit #	Issue #	Availability Factor	Rating (MW)	Problem Description	Major Outage Assessment Plan and Recommended Corrective Action	Action Items Major Outage	Resp. Engr(s)	Next Major Outage Part/Service Provider	Next Major Outage Estimated Cost ($)	Long Term Contingency Plan Cost ($)	Cap (Y/N)	Last Insp. (Year)	Target Insp. Interval (years)	Comments	Inspection Findings	Date Complete
Tufts Cove	1	HP1 (cont'd)					blocks/blades in the high temperature zones especially first few rows of the HP. Note this many not be applicable to this blade design if integral shroud construction. - Shroud OD dimensional changes (including shroud lifting as applicable). - Shroud condition (inspect for radial rubs). - General blade condition including signs of solid particle erosion (SPE) and foreign object damage (FOD). - Integrity check of the brazed connections in the blade group (as applicable) - Other recommendations are provided in PAW HP6 for the blade attachment. - Photographs of each row showing general condition as-found and as-left condition. • Develop forms to capture findings. This will allow development of a baseline for comparison at future outages for changes in blade condition. • Plan to performance smooth as required to improve heat rate. • Plan to perform a steam path audit to establish opportunities to improve heat rate.											

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Turbine-Generator Health Assessment
Outage Plan Summary

Plant	Unit #	Issue #	Availability Factor	Rating (MW)	Problem Description	Major Outage Assessment Plan and Recommended Corrective Action	Action Items Major Outage	Resp. Engr(s)	Next Major Outage Part/Service Provider	Next Major Outage Estimated Cost ($)	Long Term Contingency Plan Cost ($)	Cap (Y/N)	Last Insp. (Year)	Target Insp. Interval (years)	Comments	Inspection Findings	Date Complete
Tufts Cove	1	IPLP1	8	100	IP blade cracking, SPE, FOD, and creep damage	• Rows 1R was replaced in 1999; it is assumed the balance of IP, rows 2R – 9R, are original to the initial 1970 install of this replacement rotor. Lack of historical data impedes ability to trend issues over time. • There was no chronic evidence of rubbing detailed in the reports. Issues related to the blade attachment are discussed in PAW IPLP 5, "IPLP rotor peripheral cracking and IP dovetail cracking." • As a predictive tool, maintain turbine TSI in calibration and monitor unit vibration to detect minor changes in unbalance that may be due to shroud and blade loss.	• Continue to monitor for vibration changes as indicator of blade issues. • Confirm if IP rows 2R – 9R are original to 1970 in-service date. • Confirm general blade configuration. • Identify and procure a qualified blade repair contractor prior to next major outage. • Develop a pre-outage contingency plan for all IP rows in case any of these rows need replaced. Develop a specification for OEM and non-OEM blade vendors to bid on supply and installation either during this outage (if damage requires) or for a future outage. Accommodations for first week onsite outage inspections for suppliers should be made to ensure accurate proposals (after covers are removed. • Incorporate the following into the outage plan: - Complete MT of rotor and blades including accessible shaft radii & surfaces, underside of shroud bands (as applicable), inlet & outlet end faces of axial fit blade roots (as applicable) and blade foils. - Shroud lift checks (undershroud feeler gage) and tenon UT for all notch blocks/blades in the high temperature zones especially first few rows of the	Greg Carlin	Replace one row of IP blades Install		$120,000 $40,000	Y	2006	2014	Additional investigation is required to determine "most likely row to replace" (if any).		

Turbine-Generator Health Assessment
Outage Plan Summary

Plant	Unit #	Issue #	Availability Factor	Rating (MW)	Problem Description	Major Outage Assessment Plan and Recommended Corrective Action	Action Items Major Outage	Resp. Engr(s)	Next Major Outage Part/Service Provider	Next Major Outage Estimated Cost ($)	Long Term Contingency Plan Cost ($)	Cap (Y/N)	Last Insp. (Year)	Target Insp. Interval (years)	Comments	Inspection Findings	Date Complete
Tufts Cove	1	IPLP1 (cont'd)					HP (as applicable). - Develop a contingency plan to replace one row of IP blades (most likely 2R). - Shroud OD dimensional changes (including tile lifting as applicable). - Shroud condition (inspect for radial rubs). - General blade condition including signs of solid particle erosion (SPE) and foreign object damage (FOD). - Integrity check of the brazed connections (as applicable). - Other recommendations as provided in PAW IPLP5 for the blade attachment. - Photographs of each row showing general condition as-found and as-left condition. • Develop forms to capture findings. This will allow development of a baseline for comparison at future outages for changes in blade condition (e.g. being able to track tile lifting). • Plan to performance smooth as required to improve heat rate. • Plan to perform a steam path audit to establish opportunities to improve heat rate. • Develop non-OEM sources of blade supply to improve delivery and cost.										

Request IR-34:

For CI# 47755:

(a) Please provide NS Power's TMP – Steam Turbine – High Temperature Boiling Maintenance Practice.

(b) Please provide the total investment made to replace the steam turbine high temperature fasteners on Lingan Unit#3.

Response IR-34:

(a) Please refer to Attachment 1.

(b) The total investment made to replace the steam turbine high temperature fasteners on Lingan Unit #3 was $919,066. The primary factor in cost difference is a result of change in value of the Canadian Dollar.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

NOVA SCOTIA POWER INC. **THERMAL PLANT MAINTENANCE PRACTICES**	Practice No.:	TMP - 034
	Issue Date:	December 2008
STEAM TURBINE- HIGH TEMPERATURE BOLTING MAINTENANCE	Revision Date:	
	Revision No.:	0
Related Practices:	File No:	

INTRODUCTION:

The inspection, testing and replacement of Steam Turbine High Temperature Bolting (bolts and studs) ensure the integrity of the Steam Turbine for continued safe operation. It is essential to know the condition of the existing bolting and to anticipate the replacement of bolting that do not meet criteria for continued service. To accomplish the condition assessment the recording of each High Temperature Bolt's effective operating hours and maintenance history is required.

There are many bolts and studs used in a Steam Turbine. The function of the bolting is to maintain a tight

WORK DESCRIPTION:

This practice is the basis for managing the replacement of Steam Turbine High Temperature Bolting due to material age degradation and consumption of service life.

This practice applies to High Temperature Bolting, with an operating temperature greater than 345C, used on the Steam Turbine.
Locations of the bolting covered include: High Pressure Outer Casing, High Pressure Inner Casing, Intermediate Pressure Outer Casing, Intermediate Pressure Inner Casing, Main Stop Valve Cover, Control Valves, Reheat Stop Valve Covers, Intercept Valve Covers, Combined Reheat Valve Covers, Main and Reheat Steam Leads
joint with no steam leakage into the plant. Steam leaking from high-pressure joints may require maintenance outages and costly repairs. Unlike many plant applications, bolting used in Steam Turbine applications is often required to be slackened and retightened after periods of service to allow for component maintenance.

Steam Turbine High Temperature Bolting Maintenance Requirement:

The basic requirements for tracking Steam Turbine High Temperature Bolt consumed life are the number of tightenings, number of unit start/ stop cycles, running hours, bolt operating temperature and critical maintenance data.

The station maintenance personnel facilitate the information management required to track the operating hours, start-stop cycles, tightening events and other critical data that make up the running history of each individual High Temperature Bolt.

The maintenance crews are to report all activities, including stripped threads, bolts removed, damaged bolts, tightening events, application of thermocouples, etc.

Each individual High Temperature Bolt is identified and is returned to its original location at assembly.

	APPROVED:				
PREPARED BY: Greg Carlin	Phil Zinck	Mark Sidebottom	Mark Savory		

Supplementary Maintenance Activities:

The Actual life achieved will depend on the tightening procedure, the operating conditions, the quality of the original bolt material and the fabrication procedures used. Although the highest operating lives will be obtained with careful checks of all the important variables, in practice there will always be some uncertainty regarding actual performance. In many cases, bolts will be subjected to some non-destructive/ destructive inspections during scheduled maintenance outages to check for evidence of distress.
These supplementary inspections will typically consist of the following:

- Hammer test before disassembly (always)
- Inspection for evidence of steam leakage after disassembly of component joint (always)
- Visual inspection for defects of the bolt (always)
- Non Destructive Testing of bolt for cracks (Ultrasonic,Magnetic Particle, or Dye Penetrant)
- Hardness measurement of bolt
- Dimensional Inspection of outside diameters of shank, thread.
- Dimensional inspection of Inside diameters of nut or tapped hole
- Dimensional Stud wobble/Lean inspection
- Dimensional Inspection of Stud length
- Metallurgical inspection (Hardness and Replication)
- Destructive testing for Material Property examination (Tensile strength, yield strength, expansion, reduction of area, impact value

NON-CONFIDENTIAL

Request IR-35:

For CI# 47911:

(a) Was an EAM analysis conducted for this project? If not, why not?

(b) Please provide all analysis conducted on replacement of the high temperature fasteners with non-OEM parts. Please include all any cost estimates for non-OEM parts compared to OEM parts.

(c) Please provide any supporting documentation that leads to the conclusion that OEM parts are the most reliable.

Response IR-35:

(a) No, an EAM was not completed for this project. Please refer to SBA IR-28.

(b) NS Power does not have cost comparisons for non-OEM fasteners. Internal discussion has begun to determine approach to non-OEM components. Some early Master Service Agreements have been developed for a host of potential Turbine component supply as a contingency. NS Power turbine maintenance and component replacement is typically under the guidance of its OEMs. Independent industry experts are used to verify OEM recommendations and external non-OEM vendors are typically utilized for contingency, such as unplanned findings and rapid turnarounds.

Non-OEM vendors have been utilized in the past for smaller projects with mixed results. The re-occurring issue is that neither NS Power nor external vendors possess manufacturing drawings and data to manufacture components to original or current specifications. Due to the criticality of Turbines and the nature of Turbine Maintenance (extensive work in short outage periods) quality is a primary concern.

(c) NS Power has not concluded that there are no non-OEMs who can provide adequate replacements. While NS Power continues to explore non-OEM opportunities, it does so cautiously.

NON-CONFIDENTIAL

Request IR-36:

For CI# 47505: Please provide yearly estimates for the next 10 years of the continued capital investment of the Lingan mills that will be required to extend asset life and ensure the reliability of the equipment.

Response IR-36:

Investment in the mills at Lingan is expected to be proportional to capacity factors over the next 10 years, which should see a decrease in capital investment accordingly. However, operating at reduced loads will require additional monitoring to mitigate and plan for new failure mechanisms. This could offset the decrease expected from reduced capacity factors.

Based on anticipated capacity factors, it is projected that the average annual Lingan Mill investment (10 year view) would be less than $400,000 per year. This number would be weighted higher in the earlier years in line with capacity factors.

Request IR-37:

For CI# 46465:

(a) Was an EAM analysis conducted for this project? If not, why not?

(b) If total valve replacement is not necessary at this time, when would it be necessary?

(c) What is the extended life expectancy of the components that are being refurbished?

Response IR-37:

(a) No, an EAM was not completed for this project. Please refer to SBA IR-28.

(b) Valve components are replaced based on condition assessment and carried out during the inspection intervals.

A total valve replacement would typically only take place during a full steam chest replacement, based on the chest condition monitoring, and operation history. A strategic spare main steam chest is currently being explored with vendors. This common chest would cover a contingency replacement of Tufts Cove 2, Tufts Cove 3, Point Tupper 2, and Trenton 5 should it be required.

(c) Component life varies based on function and service. The main components being replaced in this project (valve spindles and bushings) can see 6-10 years of service, other components such as seats or reheat valve components can see even longer service life. Service life is determined primarily by condition assessment through regular inspection and OEM recommendations.

NON-CONFIDENTIAL

Request IR-38:

For CI#47613, was an EAM analysis conducted for this project? If not, why not?

Response IR-38:

An EAM analysis was not completed for this capital item as the Port Hawkesbury Biomass plant is must run generation in accordance with section 5(2A) of the Nova Scotia Renewable Electricity Regulations. In order to reliably operate the unit, this boiler refurbishment must be completed.

NON-CONFIDENTIAL

Request IR-39:

For CI# 47666, please explain the difference in costs between the 2014 (CI# 44350) and 2015 (CI# 46469) refurbishments and the refurbishment project for 2016 (CI# 47666).

Response IR-39:

Boiler refurbishment projects such as these are based on selective replacements determined by the inspection that occurs prior to and during the actual outage where the refurbishment occurs and can be expected to vary year over year. The ACE 2016 submission for CI 47666 is based on 46469 actual spending completed during the 2015 Outage. A similar amount of work is expected in 2016.

Request IR-40:

Please provide an itemized list of the projects to be completed in the 2016 Lingan Unit #4 planned outage and compare to the projects and project costs performed in the 2015 Lingan Unit #3 planned outage.

Response IR-40:

Please refer to Attachment 1, also provided electronically.

The largest driver in the cost increases from Lingan Unit #3 to Lingan Unit #4 is the decrease in value of the Canadian dollar as many materials and services are in US Dollars.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Lingan Unit #4 Outage - 2016			Lingan Unit #3 Outage - 2015		
CI#	Project Long Title	ACE 2016 Project Total	CI#	Project Long Title	ACE 2015 Project Total
47658	LIN4 L-0 Blade Replacement	4,597,152	42806	LIN3 L-0 Turbine Blade Replacements	4,157,741
47673	LIN4 Generator Rotor Rewind	2,602,159	43088	LIN3 Generator Rotor Rewind	1,901,480
47755	LIN4 Turbine High Temperature Fasteners Replacement	1,073,877	43094	LIN3 HT Fastener Replacement	868,348
43170	LIN4 AVR Replacement	842,207	37611	LIN3 - Generator Excitation & AVR System Replacement	740,497
47657	LIN4 High Voltage Bushing Refurbishment	822,570	40363	LIN3 High Voltage Bushing Refurbishment	628,531
47664	LIN4 Division Wall Replacement	619,243	46467	LIN3 - Division Wall Replacement	635,747
47869	LIN4 Bottom Ash Refurbishment	616,599	46070	LIN3 Bottom Ash Replacement	475,908
47666	LIN4 Boiler Refurbishment 2016	571,859	41233	LIN3 Boiler Refurbishment	826,133
47663	LIN4 - SH5 Boiler Tube Replacement	538,776	Not completed on Lingan Unit #3		
47689	LIN4 - Air Heater Refurbishment	521,951	46463	LIN3 - Air Heater Refurbishment	477,566
47690	LIN4 Burner Front Refurbishment	480,349	46482	LIN3 Burner Front Refurbishment	299,261
47762	LIN4 Analytical Panel Replacement	401,658	46496	LIN3 Analytical Panel Replacement	276,756
47933	LIN4 Turbine Vibration Monitoring Upgrade	238,216	Not completed on Lingan Unit #3		
47863	LIN4 Turbine Valves Refurbishment	204,548	46481	LIN3 Turbine Valve Refurbishment	194,647
43239	LIN4 BFP Proportional Recirculation Line Control	158,524	Not completed on Lingan Unit #3		
47866	LIN4 Condenser Tube Protective Coating	156,043	46532	LIN 3 Condensor Tube Protective Coating	241,868
47955	LIN4 ID FAN Shaft Refurbishment	124,952	Not completed on Lingan Unit #3		

Request IR-41:

For CI# 46352, please describe how risk profiling has provided guidance on the timing of the refurbishment.

Response IR-41:

Typically, as in this case, the risk profile brings attention to an item that is in need of some level of mitigation. Once risk reaches a threshold (a risk of 15 as described in CEJC risk matrix), a technical review ensues to determine the nature and timing of any required mitigating measures. For complex asset classes, third party, industry experts may be involved in the review. For less complex assets, plant engineers or central engineering support would be engaged to finalize timing and scope. As part of this process, as in this case, opportunities would be considered for optimizing the timing of associated work within a planned outage window of the immediate year or future years, while managing the risk

Request IR-42:

Reference CI#46587, Metro Voltage Support Add Capacitor

(a) NPSI claims that Tuft's Cove generation is committed to provide reactive power support during the combination of high transfer levels on the Onslow South transmission corridor and high system load. In addition, NSPI states (page 618 of Exhibit N-1) that Tuft's Cove is "occasionally required to be dispatched in order to provide reactive power capability in the metro Halifax area". Please provide the instances where Tuft's Cove generation was committed to satisfy these needs in the past three years. Include the Onslow South transmission flow and system load for instances where the Tuft's Cove generation was dispatched uneconomically to meet the particular reactive power needs.

(b) Please explain how Tufts Cove is dispatched uneconomically? Is the unit already committed economically at a particular level, but dispatched uneconomically to a higher level to satisfy the reactive power needs?

(c) Please provide instances where the unit was already committed economically but was dispatched at a higher level to provide reactive power for reliability. Also provide instances where the unit was committed uneconomically to meet the reactive power needs.

(d) NSPI states that (page 618 of Exhibit N-1) "By installing capacitor banks, reactive power requirements to support steady state voltage from Tuft's Cove generators can be reduced." Please explain when Tuft's Cove generator will be dispatched uneconomically to supply reactive power after the installation of the proposed capacity banks.

(e) NSPI states (page 619 of Exhibit N-1) that "A study using the system planning simulation model Plexos has concluded that a reduction in must-run Halifax based generation improves the economics of the system dispatch". Please provide this study.

(f) CI# 48025, L7018 Upgrade to 345 kV & Capacitor bank addition addresses the same reliability issues as CI#46587. Was the capacity bank addition that accompanies the L7018 upgrade included in the Plexos model evaluation for alternative B of CI# 46587? If not, why?

Response IR-42:

(a) Instances where Tufts Cove generation is committed and dispatched to provide reactive power support in the Metro Halifax area are not archived.

(b) In the context of CI 46587, constrained economic dispatch includes the concept of unit commitment and unit dispatch. Unit commitment is the decision to bring a unit on-line, whereas unit dispatch is the decision to operate an on-line unit at a level within its minimum and maximum capability. Before a Tufts Cove unit is committed, it is off-line and therefore does not provide any reactive power or contribute to MDRR. At some level of Onslow South flow, a Tufts Cove unit must be committed to provide some contribution to MDRR to support the flow. Once the unit has been 'committed' it is likely to be 'dispatched' at minimum MW generation level, and it provides a block of reactive capability to contribute to MDRR. As Onslow South flow increases and the Tufts Cove unit MW output remains at minimum, the unit's reactive power is called upon to support local MVar load and MVar support for transmission flow, therefore its reactive reserve declines. To maintain Onslow South within reliability limits, the MW output (dispatch) of the Tufts Cove unit which is on-line must increase to reduce transmission flow or a second Tufts Cove unit must be committed to increase MDRR via the second unit's reactive capability. The capacitor banks proposed in CI 46587 will relieve the reactive power load on the previously committed Tufts Cove unit to permit higher Onslow South flow, resulting in lower dispatch of the committed Tufts Cove unit, or the delay in the commitment of the additional Tufts Cove unit.

(c) Please refer to part (a).

(d) Tufts Cove generation supports both steady-state reactive power requirements and provides dynamic reactive power reserve. Tufts Cove generation may be dispatched out of merit to support either of these reactive power requirements, but it might also be dispatched thusly to avoid thermal overloading of transmission lines following a contingency. Based on the Plexos study conducted for CI 46587, there will be minimal out of merit dispatch of Tufts Cove strictly due to reactive power requirements after the installation of the proposed capacitor banks, but other factors will still result in Tufts Cove limitations.

(e) Please refer to CA IR-5.

(f) No. The project which identified the capacitor bank additions under CI 46587 was justified on its own merits using a Plexos model. The capacitor banks associated with CI 48025 are required after the upgrade of L7018 and do not provide a benefit before that upgrade. The capacitor banks associated with the upgrade of L7018 are incremental to those associated with CI 46587.

CONFIDENTIAL (Attachment Only)

Request IR-43:

Reference CI# 46591, 88S Lingan Replace 230kV GIS

(a) Please explain the need for the addition of a new air insulated breaker and a half scheme with five breakers (and provision for a sixth).

(b) Did NSPI evaluate the reliability impact of the new breaker scheme? If yes, please provide the documentation.

(c) Provide the source of the information for calculating the cost of each option listed on page 610 of Exhibit N-1. As an example, provide the vendor or other documentation used for identifying the cost of GIS breakers, SF6 dead tank breakers etc.

Response IR-43:

(a) The existing Westinghouse GIS portion of the Lingan Substation was manufactured and installed in 1978-79. It has reached its "end of life" and needs replacement. This portion of the substation includes 5 GIS circuit breakers and associated disconnect and grounding switches, PTs and GIB (Gas insulated Bus). The circuit breakers are no longer supported by the manufacturer and there is no opportunity to get any needed proprietary spare parts. The equipment is physically deteriorated, as well as experiencing SF6 gas leaking.

The existing layout of the Westinghouse equipment (5 breakers) does allow for a 6^{th} breaker. The proposed replacement with air insulated equipment is a copy to the existing electrical configuration. It was determined that an air insulated solution would be the more cost effective solution to a wholesale change out of the GIS, including all of the same vintage GIB (Gas Insulated Bus).

By the nature of NS Power's standard layout 230kV substations, the provision for a 6th breaker provides flexibility but does not add any significant cost to the project.

(b) NS Power did not perform a Substation Reliability Analysis of the new breaker scheme because operational experience with the existing breaker-and-a-half arrangement since 1980 has been acceptable.

(c) To arrive at the comparative cost estimates to the alternatives considered, current cost information was sought from venders for all of the major cost components, while the balance of plant costs, engineering, construction and commissioning costs were arrived at using our in-house experiences and costing information. Many of these cost component prices were received through verbal conversation and not through formal vendor pricing.

For air insulated equipment, NS Power has supplier of choice pricing agreements for 3 years for HV circuit breakers (MEPPI) and disconnect switches (Mindcore Technologies), which led to reliable pricing information. Please refer to Partially Confidential Attachments 1 and 2 respectively. For such things as 230kV power cable, 230kV GIS equipment and GIB, budgetary info was received from various suppliers through the aforementioned verbal conversations.

Supplier of Choice Breakers Greater than 69kV
Recommendation – P-14-243
April 2015

Submitted to:

- Hugh Kerr — Manager, Procurement
- Matt Drover — Senior Manager, Transmission & Distribution Technical Services, Reliability
- Shawn Connell — Senior Manager, Procurement (Unavailable due to Vacation)
- Paul Casey — Senior Director, T&D, Integrated Customer Service
- Craig Sutherland — Senior Director, Procurement and Retail Operations, Supply Chain and Real Estate

Prepared by: (on the direction of the Evaluation Team)

- Kathryn Richardson — Procurement Lead

Evaluation Team:

- David Downey — Senior Electrical Engineer

NSPI's objective is to select a Supplier of Choice who is competitive from a cost and quality perspective, has the ability to meet the required project timelines and meets the required specifications.

Recommendation:

The Evaluation Team recommends NSPI award the Supplier of Choice Agreement for Circuit Breakers greater than 69kV to:

- **CT Sales (Distributor of Mitsubishi Breakers)**

Total CND expenditure from this Recommendation:

ACCOUNT INFORMATION			
Project / Account Number	Currency	2015 $ Value	Description
2-012-043-800-T833	USD	$[redacted]	Five (5) 69 kV Breakers and Three (3) 138 kV Breakers
	CAD	$[redacted]	April 1, 2015 Conversion
2-012-043-800-T827	USD	$[redacted]	Two (2) 138 kV Breakers plus CTs (Separate Project)
	CAD	$[redacted]	April 1, 2015 Conversion
Total 2015 Recommended Spend	**CAD**	**$**[redacted]	

PROJECT BUDGET INFORMATION (PE or Main Item) Project Number T833		
Approved budget amount		$[redacted]
Forecast Total Project Amt		$[redacted]
Committed to Date		
Spend to Date		$[redacted]
ATO Implications		Yes:
		No

Supplier of Choice Breakers Greater than 69kV
Recommendation – P-14-243
April 2015

Process Overview:

On January 30, 2015, a Request for Proposal for a Supplier of Choice Agreement for Circuit Breakers greater than 69kV was issued to the following companies:

- [redacted]
- CT Sales
- [redacted]

By the Close Date, February 27, 2015, the following 5 proponents decided to submit proposals for this project:

- [redacted]
- CT Sales
- [redacted]

The evaluation of the bid focused on the following Key Selection Criteria:

- Understanding and ability to meet Specification requirements
- Speed and efficiency of delivery methods and timelines
- Pricing
- Experience in the industry and reputation of Supplier / Manufacturer
- Warranty

Supplier of Choice Breakers Greater than 69kV
Recommendation – P-14-243
April 2015

Nova Scotia POWER An Emera Company

Technical and Commercial Evaluation:

For the following reasons, [redacted] and [redacted] were unable to meet the required specifications provided in the RFP:

- [redacted]
- [redacted]
- [redacted]

The proponents were asked to provide firm pricing for 2015-2017 for 7 breaker types commonly used by NSPI. Estimated quantities were available for 2016-2017 for two of these breaker types along with firm volumes for 2015. Quotes were also obtained for the breaker types without firm or estimated quantities to allow for expedited purchasing in the event of a breaker failure.

The following chart outlines the various breakers requested and the estimated volumes provided to proponents:

NSPI Estimated Quantities								
Year	Unit of Measure	69kV-1.2	69kV-2	138kV-1.2	138kV-2	230kV-2	230-kV-3	345k-3
2015 Estimated Quantity	Units	5		5				
2016 Estimated Quantity	Units	5		3				
2017 Estimated Quantity	Units	5		3				

As CT Sales and [redacted] each provided proposals which met the required specification, their bids were commercially evaluated. The following chart shows the pricing, delivery timeline, warranty and payment terms provided by each proponent for each breaker type:

Vendor	Factor	Unit of Measure	69kV-1.2	69kV-2	138kV-1.2	138kV-2	230kV-2	230-kV-3	345k-3	Total
					ABB Inc.					
[redacted]	Unit Price (Firm 2015-2017)	CAD	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	
[redacted]	Total Value 2015	CAD	$ [redacted]	$ -	$ 532,890.00	$ -	$ -	$ -	$	$ [redacted]
[redacted]	Total Value 2016+2017	CAD	[redacted]	$	[redacted]	$ -	$ -	$ -	$	$ [redacted]
[redacted]	Unit Price (Firm 2015-2017)	USD	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	
[redacted]	Total Value 2015	USD	$ [redacted]	$ -	[redacted]	$ -	$ -	$ -	$	$ [redacted]
[redacted]	Total Value 2016+2017	USD	[redacted]	$	[redacted]	$ -	$ -	$ -	$	$ [redacted]
									Total 3 Year Contract CAD	$ [redacted]
									Total 3 Year Contract USD	$ [redacted]
[redacted]	Warranty	Years	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	Extended Warranty Option	(Y/N)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	Extended Warranty Cost	CAD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	Payment Terms	Days	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
					CT Sales					
CTS	Unit Price (Firm 2015-2017)	CAD	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	
CTS	Total Value 2015	CAD	[redacted]	$	[redacted]	$ -	$ -	$ -	$	$ [redacted]
CTS	Total Value 2016+2017	CAD	$ [redacted]	$ -	[redacted]	$ -	$ -	$ -	$	$ [redacted]
CTS	Unit Price (Firm 2015-2017)	USD	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	
CTS	Total Value 2015	USD	[redacted]	$	[redacted]	$ -	$ -	$ -	$	$ [redacted]
CTS	Total Value 2016+2017	USD	[redacted]	$	[redacted]	$ -	$ -	$ -	$	$ [redacted]
									Total 3 Year Contract CAD	$ [redacted]
									Total 3 Year Contract USD	$ [redacted]
CTS	Warranty	Years	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
CTS	Extended Warranty Option	(Y/N)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
CTS	Extended Warranty Cost	CAD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
CTS	Payment Terms	Days	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

CT Sales provided the best pricing, warranty and delivery timelines of the two proposals. NSPI has been purchasing Mitsubishi breakers through this vendor for many years and this product has had an excellent track record in terms of quality and delivery schedule. For these reasons, CT Sales' proposal scored highest of all proposals submitted. Please see Appendix A for a full breakdown of vendor scoring for each criteria listed above.

Four (4) pricing alternatives were ultimately offered by CT Sales. The evaluation team analyzed these alternatives using the firm 2015 volumes and the 2016-17 estimated volumes to determine the best pricing option. The estimated 3 year contract totals for each option are shown below in green:

Supplier of Choice Breakers Greater than 69kV
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April 2015

Nova Scotia POWER An Emera Company

CT Sales				
Factor	**Unit of Measure**	**69kV-1.2**	**138kV-1.2**	**Total**
Option 1: Unit Price (Firm 2015-2017)	CAD	$ [redacted]	$ [redacted]	
Total Value 2015	CAD	$ [redacted]	$ [redacted]	$ [redacted]
Total Value 2016+2017	CAD	$ [redacted]	$ [redacted]	$ [redacted]
			Total 3 Year Contract	$ [redacted]
Option 2: Unit Price (Firm 2015-2017)	USD	$ [redacted]	$ [redacted]	
Total Value 2015	USD	$ [redacted]	$ [redacted]	$ [redacted]
Total Value 2016+2017	USD	$ [redacted]	$ [redacted]	$ [redacted]
			Total 3 Year Contract	$ [redacted]
Option 3: 2015-CAD firm within bandwidth +/-3 pts. (base rate = 1/1.2603)	CAD	$ [redacted]	$ [redacted]	
Total Value 2015	CAD	$ [redacted]	$ [redacted]	$ [redacted]
Option 3: 2016-CAD firm within bandwidth +/-3 pts.	CAD	$ [redacted]	$ [redacted]	
Total Value 2016	CAD	$ [redacted]	$ [redacted]	$ [redacted]
Option 3: 2017-CAD firm within bandwidth +/-3 pts.	CAD	$ [redacted]	$ [redacted]	
Total Value 2017	CAD	$ [redacted]	$ [redacted]	$ [redacted]
			Total 3 Year Contract	$ [redacted]
Option 4: Firm 2015-USD	USD	$ [redacted]	$ [redacted]	
Total Value 2015	USD	$ [redacted]	$ [redacted]	$ [redacted]
Option 4: Firm 2016-USD	USD	$ [redacted]	$ [redacted]	
Total Value 2016	USD	$ [redacted]	$ [redacted]	$ [redacted]
Option 4: Firm 2017-USD	USD	$ [redacted]	$ [redacted]	
Total Value 2017	USD	$ [redacted]	$ [redacted]	$ [redacted]
			Total 3 Year Contract	$ [redacted]

Option 4 presented the best value and least risk to NSPI over the life of the contract. Purchasing the breakers in the USD proposed saves NSPI a projected 8% over the firm 2015-17 CAD price offered and 1% over the firm 2015-17 USD price.

The evaluation team spoke with the Treasury team to ensure purchasing 2015 volumes in USD was acceptable. Their recommendation was to purchase in USD based on exchange rate forecasts and the vendor's USD vs. CAD offer.

[redacted]

<u>Recommendation:</u>

The evaluation team confidently presents this Recommendation and believes the process was both competitive and transparent and requests your approval.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Appendix A:

Bid Comparison Worksheet

#	Evaluation Criterion	Criterion Weighting (%) Revise Weightings based on Project requirements	Bidders					Key Differentiator Between Proposals - (The significant proposal indicators driving the extreme highs or lows within the scoring)
			[redacted]	[redacted]	[redacted]	CT Sales	[redacted]	
			Rank 1-3 1 - Does not meet requirements 2 - Meets requirements 3 - Exceeds requirements					
1	Understanding and ability to meet specification requirements	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Score		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2	Speed and efficiency of delivery methods and timelines	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Score		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
3	Pricing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Score		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
4	Experience in the industry and reputation of Supplier / Manufacturer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Score		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
5	Warranty	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Score		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
	TOTAL SCORE	100.0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Supplier Of Choice-Air Switches
Recommendation – P-14-234
August 2015

Nova Scotia POWER An Emera Company

Submitted to:

- Matt Drover — Senior Manager, T&D Technical Services, Reliability
- Jason Penny — Director, Procurement

Prepared by: (on the direction of the Evaluation Team)

- Hugh Kerr — Procurement Manager

Evaluation Team:

- David Downey — Senior Engineer, T&D Technical Services
- Bob Johnson — Engineer, T&D Technical Services -Consultant

NSPI's objective is to select a Service Provider who is competitive from a cost and quality perspective, has the ability to meet the required project timelines and meets the required specifications.

NSPI requires the partner of choice for the supply of Air Switches. This initiative was created for the following reasons

- -Establish standard offerings and usage
- -Establish consistent budgetary supply cost for the next three years
- -Enable the supplier to plan production (delivery time delay avoidance)

Recommendation:

The Evaluation Team recommends NSPI award the **SOCA for AIR-Switches to**

Mindcore

Total CND expenditure from this Recommendation:

ACCOUNT INFORMATION			
Project / Account Number	**Currency**	**$ Value**	**Description**
	CND	$[redacted]	**From the Menu of 12 –est.6 will be commonly utilized**
	CND		***Please note-this is is an estimated value based upon forecasts of the spend that maybe spent by NSPI over life of agreement**
	CND		
Total Forecasted Spend 3 years	**CND**		

PROJECT BUDGET INFORMATION (PE or Main Item)		
Approved budget amount		
Forecast Total Project Amount	**The charges centers will be determined by capital spend accounts and will be filled out at time of order.**	
Committed to Date		
Spend to Date		
ATO Implications		**Yes:**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Supplier Of Choice-Air Switches
Recommendation – P-14-234
August 2015

	x	No:

Switch Type	Est. Quantities for 2015	[redacted]	[redacted]	Mindcore (CDN)
Type 1 (27 kV , 1200A **, Cu, Hook stick)	24	[redacted]	625. US$	685.00
Type 2 (72.5 kV, 1200A, Al, Vert. Break, Vert. Mount)	4	[redacted]	10842. US$	6,660.00
Type 3 (72.5 kV, 2000A, Al., Vert. Break, Vert. Mount)		[redacted]	11142. US$	7,650.00
Type 4 (145 kV, 1200A, Al., Vert. Break, Vert. Mount)		[redacted]	10611. US$	9,995.00
Type 5 (145 kV, 2000A, Al., Vert. Break, Vert. Mount)		[redacted]	11011. US$	11,270.00
Type 6 (72.5 kV, 1200A, Al., Vert. Break, Horiz. Mount)	2	[redacted]	10842. US$	6,660.00
Type 7 (72.5 kV, 2000A, Al. , Vert. Break, Horiz. Mount)		[redacted]	11142. US$	7,650.00
Type 8 (145 kV, 1200A, Al., Vert. Break, Horiz. Mount)	4	[redacted]	10611. US$	9,995.00
Type 9 (145kV, 2000A, Al. , Vert. Break, Horiz. Mount)		[redacted]	11011. US$	11,270.00
Type 10 (72.5 kV, 1200A, Al., Side Break, Vert. Mount)		[redacted]	[redacted]	[redacted]
Type 11 (145 kV, 1200A, Al., Centre Break, Vert. Mount)		[redacted]	[redacted]	[redacted]
Warranty		[redacted]	[redacted]	[redacted]
				[redacted]
Pricing conditions		[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	
			[redacted]	[redacted]
			[redacted]	
Delivery		[redacted]	[redacted]	
Quick Break Whips addition		[redacted]	[redacted]	[redacted]
Motor Operator				[redacted]
Price Validity Period		[redacted]	[redacted]	[redacted]
Technical Acceptability		[redacted]	[redacted]	[redacted]

Supplier Of Choice-Air Switches
Recommendation – P-14-234
August 2015

Nova Scotia POWER An Emera Company

Process Overview:

The following is a list of disconnect switch manufacturers that submitted a proposal to our RFP-14-234;
1) [redacted]
2) [redacted]
3) [redacted]
4) [redacted]
5) Mindcore Technologies
6) [redacted]

Of the above submissions, only 3 manufacturers provided the full suite of pricing & information requested;
1) [redacted]
2) [redacted]
3) Mindcore Technologies

Technical Evaluation:

A technical review of the switch proposals was conducted.
NSP has purchased disconnect switches from all of the above mentioned manufacturers in the past, and all are technically acceptable, however, some are more robust and have better design features than others that, in our experience, would lead to longer trouble free service life.
[redacted] Mindcore Technologies is a Canadian manufacturer. Mindcore, although a relatively new player in the switch business compared to C/P and SS, their pedigree comes from the acquisition of switch manufacturers designs , molds , etc. that include Kearney National, Pursley 2000, and Dominion Cutout. (All very good switch manufactures of the past) . In many cases, they have improved on these old designs to provide an even better product.
Recently, Mindcore has been working with us to provide parts/components for our 230kV switch refurbishment program as well as recently supplied 2- 345kV disconnect switches at Onslow.

Commercial Evaluation:

Upon review it was found that Mindcore had the more competitive bid. In order to solidify pricing in this category and ensure that the pricing and offering was optimum further discussions (negotiations) took place the result was as shown:

Mindcore (CDN)	Year Total	Mindcore (CDN)	Year Total				
					year 1	year two	Year Three
[redacted]	$ [redacted]	$ [redacted]	$ [redacted]		[redacted]	[redacted]	[redacted]
[redacted]	$ [redacted]	$ [redacted]	$ [redacted]				
[redacted]	$ -	$ [redacted]	$ [redacted]				
[redacted]	$ -	$ [redacted]	$ [redacted]				
[redacted]	$ -	$ [redacted]	$ [redacted]				
[redacted]	$ [redacted]	$ [redacted]	$ [redacted]				
[redacted]	$ -	$ [redacted]	$ [redacted]				
[redacted]	$ [redacted]	$ [redacted]	$ [redacted]				
[redacted]	$ -	$ [redacted]	$ [redacted]				
[redacted]	$ -	$ [redacted]	$ [redacted]				
[redacted]	$ -	$ [redacted]	$ [redacted]				
	$ [redacted]		$ [redacted]		[redacted]	[redacted]	[redacted]
[redacted]		5					
[redacted]		included	[redacted]				[redacted]
2015 prices shown		Fixed					
add [redacted] for each out year						Cost Avoidance	$ [redacted]

[redacted] Also the supplier and NSPI have concluded that for the sake of delivery times and better production coordination-the supplier and NSPI shall meet at the end of the year to review the future year's requirements (non-committal). This creates a more partnership environment and enables both parties flexibility.

Recommendation:

The evaluation team confidently presents this recommendation and believes the process was both competitive and transparent and requests your approval.

Request IR-44:

Reference CI# 46811, 2H Armdale Transformer addition

(a) Please indicate the reason for adding the new transformer now instead of a subsequent years since the load growth will not materialize until 3-5 years in the future.

(b) How are the loading and contingency concerns described on page 654 of Exhibit N-1 alleviated today when there is no additional transformer?

(c) Please indicate whether NSPI conducted a least-cost solution or other economic analysis for this project? If so, please provide the results.

(d) Is there a mobile transformer available for contingency/maintenance needs? Why or why not?

Response IR-44:

(a) Please refer to Attachment 1 to CI 46811 (*Peninsular Halifax and Area Distribution Planning Study Report number 342-1113-H50*) at page 657 of the 2016 ACE Plan. In addition, of the three main substations supporting the peninsula (104H Kempt Rd, 1H Water St, and 2H Armdale), Armdale is the only one without any form of redundant voltage transformation capacity. In the event of a transformer failure on the peninsula, both 104H and 1H have adjacent transformers that are capable of picking up affected customers. With only a single transformer available at Armdale, if that transformer were to fail, full restoration of all the affected customers could require the installation of a mobile substation. Given the geographical location of the Armdale substation and the physical dimensions of the mobile substation, the time of day, traffic, weather, and other ambient conditions can heavily impact the time required to transport and energize the mobile substation. With a second transformer available at the site, NS Power would have increased flexibility and ability to restore affected customers in the event of a failure in a more expeditious fashion and potentially remove the need to install a mobile substation.

(b) Generally, NS Power has sufficient capability to transfer the existing customer load from 2H Armdale to adjacent stations. In doing so, the equipment at adjacent stations can be stressed to a greater degree than normal and the rate of loss-of-life of said equipment can be impacted. It is more advantageous to have the capability to transfer load in a contingency situation without placing undue stress on adjacent substations and potentially accelerating future equipment failures.

(c) Please refer to Appendix C to Attachment 1 of CI 46811 (*Peninsular Halifax and Area Distribution Planning Study Report number 342-1113-H50*).

(d) A mobile substation is available as a contingency for 2H Armdale substation. Good utility practice calls for the application of a mobile substation in order to restore service in a contingency situation where there is insufficient capability or increased risk associated with transferring load to an adjacent station. A mobile substation can generally be brought on-line to restore service to customers in a more expeditious fashion than moving a full-sized spare transformer from NS Power’s spare storage facility. The mobile substation provides service to customers while the more long-term activity of installing a permanent replacement for the failed transformer takes place. The mobile substation is also available for maintenance needs as it can provide temporary service to customers while their power transformer is taken out of service and maintained.

Request IR-45:

Reference CI# 44981, 2C Port Hastings Transformer Replacements

(a) **Indicate the reason for having two transformers under the current configuration instead of one. Why replace the two transformers with one? Did NSPI conduct a reliability assessment of the new configuration? If not why? If yes, please provide the documentation.**

(b) **Please provide the one line diagrams of the existing and future configuration.**

(c) **Indicate whether NPSI conducted an economic analysis on the replacement of one versus two transformers? If so, please provide the results of the analysis.**

Response IR-45:

(a) Two transformers were previously required at 2C because 69kV Line 5503 used to be in service between 2C Port Hastings and 22C Cleveland; therefore, there was a need to have both 69kV (transmission) and 25kV (distribution) voltages at 2C Port Hastings. Now that Line 5503 has been retired, there is no longer a requirement for the 69kV source at 2C, hence no need for the extra transformer. A review of the overall reliability impact of the new configuration demonstrates an overall decrease in risk associated with the simplification of the system from two units in series, to a single unit design.

(b) Confidential Attachment 1 illustrated the before and after single line for 2C Port Hastings.

(c) The 138 to 69kV transformation is no longer required due to the retirement of L-5503. It will be less expensive to purchase one transformer instead of two transformers. An economic analysis was not conducted on the replacement of one versus two transformers.

SBA IR-45 Attachment 1 has been removed due to confidentiality.

Request IR-46:

Reference CI# 48061 New Mobile Substation 69-25/12-4kV, 6 MVA

(a) Please provide the times where customers lost service due to the unavailability of a back up to the existing 3P mobile substation in the last 5 years?

(b) Please provide all reliability criteria documentation that mandate the availability of two 3P mobile substations in NSPI's area.

(c) NSPI states (page 824 of Exhibit N-1) that "Delaying the project will mean customers supplied by this type of transformer are still exposed to the risk of a prolonged power outage." What is the longest time the existing mobile substation was used in the past 3 years for a maintenance outage? Can NPSI personnel terminate maintenance early to free the existing mobile transformer so it can be used to restore power for customers that have no service due to an unforeseen contingency?

Response IR-46:

(a) There are no instances of customers losing service due to unavailability of the 3P mobile substation within the last five years. Nonetheless, an outage on one of the transformers previously identified would likely be longer than necessary if the 3P mobile was installed for maintenance and a suitable back-up was unavailable.

(b) There are no specific reliability criteria that would mandate two 3P mobile substations within NS Power's area. Please refer to part (a).

(c) The longest time that the existing 3P mobile has been installed for a maintenance outage within the last 3 years is 6 weeks. If 3P mobile was installed for maintenance and one of the previously identified units failed, customers supplied from that substation could experience a 3-5 day outage depending how far along maintenance activities had progressed.

Request IR-47:

Reference CI# 48066, 2016/2017 Substation Polychlorinated Biphenyl (PCB) Equipment Removal Program

(a) Please explain why NSPI is proposing to replace PCB equipment where sampling is not feasible. Provide the reasons for the inability for sampling the aforementioned equipment.

(b) Was the schedule for replacement of the affected PCB equipment changed due to the extension received on January 1, 2015? What was the schedule for replacing the equipment before January 1, 2015 and what is the current schedule? Please provide documentation for both.

(c) Provide the testing results for the 100 breakers that do not meet the new Regulations. What is the constraint for not replacing more of the affected equipment sooner?

Response IR-47:

(a) Not all substation asset bushings have an oil sample port and, as a result, obtaining a sample would involve removing the bushing from service and drilling into the side of the bushing. In this case, obtaining a sample would destroy the bushing or significantly compromise its integrity. In these situations, replacement of the equipment is recommended.

(b) Yes, the schedule for replacement was affected by the extension that was received on January 1, 2015. Prior to the extension, authorization was received to complete the planned replacement of all equipment confirmed to contain a PCB concentration of 500 mg/kg or more by December 31, 2014. The current schedule now requires that all equipment which has a known PCB concentration of 50 mg/kg – 499 mg/kg must be removed by December 31, 2025.[1] Please refer to Attachment 1 and Attachment 2 for the schedule up to December 31, 2014.

Please refer to Attachment 3 for the remaining PCB items to be sampled. Anytime a device is undergoing an out-of-service maintenance, if sampling is required it will be completed at that time. To help make this effective, at the start of each year replacement material is ordered to help ensure that when devices come out of service replacements can occur. This out of service maintenance frequency is at most 8 years so therefore all items that require sampling / replacement will be completed by the end of 2023.

Please refer to Attachment 4 for the remaining PCB items to be replaced. Each year approximately 12 breakers (96 breakers in total) are selected for replacement based on risk and maintenance cycles. Transformer bushings are replaced as the transformer is taken out of service for maintenance and will all be replaced by the end of 2023 as they are on an 8 year frequency. Each year approximately 40 bushings (304 in total) are replaced as the unit is out of service.

(c) Please refer to Attachment 5, also provided electronically, which shows the PCB information for the 100 breakers that do not meet the new regulations. The two main constraints for not replacing the affected equipment sooner would be transmission system outage and resource (internal and external) constraints.

[1] PCB Regulations, Section 16(1)(b)(ii).

Environment Canada / Environnement Canada

Nova Scotia Power Inc.
P.O. Box 910
Halifax, Nova Scotia B3J 2W5

20 April 2011 / 20 avril 2011

EXTENSION OF DECEMBER 31, 2009 END-OF-USE DATE FOR EQUIPMENT AND LIQUIDS CONTAINING PCBs Granted Under Subsection 17(2) of the *PCB Regulations*

PROLONGATION DE LA DATE DE FIN D'UTILISATION DU 31 DÉCEMBRE 2009 POUR DES PIÈCES D'ÉQUIPEMENT ET DES LIQUIDES QUI CONTIENNENT DES BPC Accordée en vertu du paragraphe 17(2) du *Règlement sur les BPC*

File Number / No. de dossier: 09/062/EXT-R

The Department of the Environment grants Nova Scotia Power Inc., Halifax, the extension requested in its application. The end-of-use date of the equipment and liquids used for their servicing described below is extended from December 31, 2009 to the dates indicated in the table below.

Le ministère de l'Environnement accorde à Nova Scotia Power Inc., Halifax, la prolongation exigée dans sa demande. La date de fin d'utilisation des pièces d'équipement et des liquides nécessaires à leur entretien décrits ci-dessous est reportée du 31 décembre 2009 aux dates indiquées au tableau ci-dessous.

This extension is granted in accordance with subsection 17(2) of the *PCB Regulations*. The condition specified in subparagraph 17(2)(*a*)(i) of the Regulations and referred to in the application is met.

Cette prolongation est accordée en vertu du paragraphe 17(2) du *Règlement sur les BPC*. La condition énoncée au sous-alinéa 17(2)*a*)(i) du Règlement et invoquée dans la demande est remplie.

Number of pieces of equipment / Nombre de pièces d'équipement	Extension date/Date de prolongation
1456	31 December 2010
1330	31 December 2011
828	31 December 2012
749	31 December 2013
831	31 December 2014
Total - 5194	

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Condition referred to in the application for an extension /
Condition invoquée dans la demande de prolongation

The equipment is being replaced with equipment that is engineered to order, and it is not technically feasible to replace the equipment on or before December 31, 2009.

Les pièces d’équipement doivent être remplacées par des pièces d’équipement conçues et fabriquées sur mesure et il est techniquement impossible de le faire le 31 décembre 2009 ou avant cette date.

Applicant and person authorized to act on applicant’s behalf
Demandeur et personne autorisée à agir en son nom

Applicant/ Demandeur, 17(3)(a)
Nova Scotia Power Inc.
P.O. Box 910,
Halifax , Nova Scotia B3J 2W5

Person authorized to act on applicant’s behalf/ Personne autorisée à agir au nom du demandeur, 17(3)(a)
Mr. Terry Toner
(P) (902) 428-6744
(E) terry.toner@nspower.ca

Owner of equipment containing PCBs/ Propriétaire des pièces d’équipement contenant des BPC, 17(1)
Same as applicant above.

Description and location of equipment and liquids needed for their servicing /
Description et emplacement des pièces d’équipement et des liquides nécessaires à leur entretien

See attached list of equipment for details, this list is part of the authorization /
Voir la liste des pièces d’équipements annexée pour le détail, cette liste fait partie intégrante de l’autorisation

Type and function of the equipment/ Type et fonction de l’équipement, 17(3)(b)(i): 5,194 pieces of equipment in substations either transmitting power from generation units to large customer load centres at voltage levels of 69,000 volts or higher or distributing power to mostly residential and small industrial customers at 25,000 volts or less: 8 transformers, 4,546 bushings, 31 circuit breakers, 17 capacitors, 310 potential transformers (PT), 181 current transformers (CT) and 101 capacitance voltage transformer (CVT). See Table 1 below for details.

Quantity of liquid (litres) containing PCBs in the equipment, 17(3)(b)(ii): Using the following liquid quantities per unit, all 5,194 pieces of equipment contain an estimated 157,775 Litres of liquid containing PCBs.
Five transformers x 200L/unit = 1600 L, three transformers x 110L/u = 330L, 4,546 bushings x 20 L/unit = 90,920 L, 31 circuit breakers x 200L/unit = 6,200 L, 17 capacitors x 5 L/unit = 85 L, 310 potential transformers (PT) x100 L/unit = 31,000 L, 181 current transformers (CT) x100L/unit = 18,100 L and 101 capacitance voltage transformer (CVT) x100L/unit = 10,100 L.

Quantity of liquid (litres) containing PCBs needed for its servicing/ Quantité de liquide (litres) contenant des BPC nécessaire à son entretien, 17(3)(b)(ii): No additional liquids are kept for the purpose of servicing the working equipment.

Concentration of PCBs (mg/kg) in the liquid/ Concentration de BPC (mg/kg) dans le liquide, 17(3)(b)(iii): An average estimated PCB concentration of 647 mg/kg is used, based on the PCB concentration of known PCB contaminated equipment.

Quantity of PCBs (kg) in the liquid/ Quantité de BPC (kg) dans le liquide/, **17(3)(b)(iv)**:
As indicated in table below the total estimated quantity of PCBs in the liquid for all 5,194 pieces of equipment is 92.893 kg. An average estimated density of 0.91 kg/L is used, based on known PCB contaminated equipment.

Name-plate description, manufacturer's serial number/ Plaque d'identification et numéro de série, 17(3)(b)(v) : Name-plate description and serial numbers is not provided due to the number of equipment and inaccessibility at the moment.

Unique identification number on the label required under section 29/ Numéro d'identification unique sur l'étiquette conformément à l'article 29, 17(3)(c): See column entitled "Unique Identification Number" in the table attached below. All the equipment identified in the Application for Extension is in use and has an unknown PCB concentration. The labeling, as required under Section 29, must have a unique identification number and contain the statement "ATTENTION – contains 50 mg/kg or more of PCBs / contient 50 mg/kg ou plus de BPC". NSPI will apply this label within 30 days, as appropriate, when information specific to the presence of PCB is available.

Place where the equipment is located/ Endroit où se trouve la pièce d'équipement, 17(3)(d): The equipment is located in specific substations that are identified in the Table below.

Information demonstrating that it is not technically feasible to replace the equipment with equipment that is engineered to order on or before December 31, 2009/ Renseignements qui établissent qu'il est techniquement impossible de remplacer la pièce d'équipement conçue et fabriquée sur mesure le 31 décembre 2009 ou avant cette date, 17(3)(e): The information provided in the application for an extension in accordance with this section indicate that the applicant is meeting the condition specified in subparagraph 17(2)*a*)(i).

Necessary measures taken to minimize or eliminate any harmful effect of the PCBs that are contained in the equipment on the environment and human health/ Mesures nécessaires prises

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pour éliminer ou atténuer tout effet nocif des BPC contenus dans la pièce d'équipement sur l'environnement et la santé humaine, 17(3)(f): The measures are indicated in the application for an extension.

Plan for ending the use of equipment by the end of the extension along with timelines/ Plan et échéancier mis en oeuvre afin que l'utilisation de la pièce d'équipement cesse à la fin de la prolongation, 17(3)(g): Provided in the application for an extension. The 5,194 pieces of equipment will be removed by December 31, 2014.

Plan for inspecting equipment/ Plan d'inspection de la pièce d'équipement, 17(3)(h): Monthly inspections will be conducted for the period of the extension for damage that could lead to the release of PCBs.

Please take note that it is your responsibility as the owner or the person who controls or possesses the equipment and liquids containing PCBs to ensure that the requirements set out in the *PCB Regulations* made pursuant to CEPA 1999 are complied with at all time.

Veuillez noter qu'en tant que propriétaire ou personne qui contrôle ou possède les pièces d'équipement et des liquides contenant des BPC il vous incombe de veiller à ce que les exigences établies dans le *Règlement sur les BPC* et dans la LCPE (1999) soient remplies en tout temps.

Signed for and on behalf of the Minister of the Environment /
Signé au nom du ministre de l'Environnement

Tim Gardiner
Director / Directeur
Waste Reduction & Management / Réduction et gestion des déchets
Public and Resources Sectors / Secteurs publics et des ressources
Environment Canada / Environnement Canada

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Table 1

Substation Location	Location (17(3)(d))	Unique Identification Number (Labels) (17(3)(c)&29)	Quantity of Liquid containing PCBs (L) (17(3)(b)(ii))	*Concentration of PCB (mg/kg) (17(3)(b)(iii))	**Quantity of PCB in the liquid (kg) (17(3)(b)(iv))	Type and function of equipment (17(3)(b)(i))	Number of type of Equipment	End-of-Use Date
Metro Region								
Aerotech	20 Old Guysborough Road (Off Aerotech Drive)	127H	180	647	0.106	Bushing	9	31-Dec-10
			180	647	0.106	Bushing	9	31-Dec-11
Akerley Blvd	Akerlyey Boulevard, Dartmouth (Half Way Up)	124H	360	647	0.212	Bushing	18	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-14
Albro Lake	18 Sea King Drive, Dartmouth	62H	140	647	0.082	Bushing	7	31-Dec-13
Armdale	7144 Chebucto Road, Halifax	2H	360	647	0.212	Bushing	18	31-Dec-10
Beaufort	Across From 1069 Beaufort Avenue, Halifax	7H	400	647	0.236	Breaker	2	31-Dec-11
			400	647	0.236	Breaker	2	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-14

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Bedford	7 Balsam Rd, (Off Dartmouth Road, Next To Railway)	100H	140	647	0.082	Bushing	7	31-Dec-13
Brushy Hill	379 Brushy Hill Road, Mount Uniacke	120H	580	647	0.341	Bushing	29	31-Dec-10
			1700	647	1.001	CVT	17	31-Dec-10
			200	647	0.118	Bushing	10	31-Dec-11
			20	647	0.012	Bushing	1	31-Dec-13
			200	647	0.118	Bushing	10	31-Dec-14
			100	647	0.059	PT	1	31-Dec-14
Burnside Gas Turbine Plant	2 Vidito Drive, Dartmouth	14H	200	647	0.118	Bushing	10	31-Dec-11
			200	647	0.118	Bushing	10	31-Dec-13
Burnside Substation	2 Vidito Drive, Dartmouth	108H	100	647	0.059	Bushing	5	31-Dec-10
			300	647	0.177	Bushing	15	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			440	647	0.259	Bushing	22	31-Dec-13
			140	647	0.082	Bushing	7	31-Dec-14
			100	647	0.059	CVT	1	31-Dec-11
			500	647	0.294	PT	5	31-Dec-12
			100	647	0.059	PT	1	31-Dec-14
Cobequid Road	89 Cobequid Road, Sackville	101H	740	647	0.436	Bushing	37	31-Dec-10

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			360	647	0.212	Bushing	18	31-Dec-11
			140	647	0.082	Bushing	7	31-Dec-12
			20	647	0.012	Cap Bank	4	31-Dec-12
			100	647	0.059	PT	1	31-Dec-13
Dartmouth East	933 Hwy #7, Dartmouth	113H	10	647	0.006	Cap Bank	2	31-Dec-10
			1500	647	0.883	CT	15	31-Dec-10
			100	647	0.059	CVT	1	31-Dec-10
			700	647	0.412	PT	7	31-Dec-10
Dockyard (New)	Near The Centre Gate Barrington Street, Halifax	630H	120	647	0.071	Bushing	6	31-Dec-11
Dockyard Recloser North	Near The South Gate Barrington Street, Halifax	11H	120	647	0.071	Bushing	6	31-Dec-10
Elmsdale	47 Elmsdale Road, Elmsdale	82V	240	647	0.141	Bushing	12	31-Dec-10
			240	647	0.141	Bushing	12	31-Dec-11
			260	647	0.153	Bushing	13	31-Dec-13
			5	647	0.003	Cap Bank	1	31-Dec-13
			100	647	0.059	CVT	1	31-Dec-13
			100	647	0.059	PT	1	31-Dec-13
Fairview	3588 Percy Street, Halifax	8H	140	647	0.082	Bushing	7	31-Dec-11
Farrell Street	288 Windmill Road, Dartmouth	99H	240	647	0.141	Bushing	12	31-Dec-10

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			480	647	0.283	Bushing	24	31-Dec-13
			500	647	0.294	Bushing	25	31-Dec-14
			100	647	0.059	PT	1	31-Dec-11
			200	647	0.118	PT	2	31-Dec-13
Goodwood Wind Turbine		136H	120	647	0.071	Bushing	6	31-Dec-10
Halifax Shipyard Recloser	Main Gate Shipyards Barrington Street, Halifax	115H	120	647	0.071	Bushing	6	31-Dec-12
Imperial Oil	581 Pleasant Street, Dartmouth	58H	240	647	0.141	Bushing	12	31-Dec-11
			380	647	0.224	Bushing	19	31-Dec-12
			240	647	0.141	Bushing	12	31-Dec-13
			5	647	0.003	Cap Bank	1	31-Dec-12
			300	647	0.177	CT	3	31-Dec-11
			600	647	0.353	PT	6	31-Dec-14
Kearney Lake Road	160 Kearney Lake Road, Halifax	129H	360	647	0.212	Bushing	18	31-Dec-12
Kempt Road	3184 Kempt Road, Halifax	104H	960	647	0.565	Bushing	48	31-Dec-10
			740	647	0.436	Bushing	37	31-Dec-11
			500	647	0.294	Bushing	25	31-Dec-12
			10	647	0.006	Cap Bank	2	31-Dec-12
			700	647	0.412	PT	7	31-Dec-13

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Lakeside	39 Lakeside Park Drive	103H	480	647	0.283	Bushing	24	31-Dec-10
			600	647	0.353	CVT	6	31-Dec-10
			300	647	0.177	PT	3	31-Dec-10
			120	647	0.071	Bushing	6	31-Dec-11
			360	647	0.212	Bushing	18	31-Dec-13
			680	647	0.400	Bushing	34	31-Dec-14
			5	647	0.003	Cap Bank	1	31-Dec-13
			100	647	0.059	PT	1	31-Dec-13
			200	647	0.118	PT	2	31-Dec-14
			200	647	0.118	St. Service TRN	1	31-Dec-14
Lucasville Road	249 Lucasville Road	131H	120	647	0.071	Bushing	6	31-Dec-10
			120	647	0.071	Bushing	6	31-Dec-11
			240	647	0.141	Bushing	12	31-Dec-12
Maple Street	1 Maple Street, Dartmouth	54H	480	647	0.283	Bushing	24	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-11
Marginal Road	Behind 730 Marginal Road, Halifax	4H	120	647	0.071	Bushing	6	31-Dec-11
Mobile 5P	not applicable	5P	200	647	0.118	Bushing	10	31-Dec-11
Musquodoboit Harbour	7 Scott’s Lake Road	87H	360	647	0.212	Bushing	18	31-Dec-10
Penhorn Dartmouth	24 Prentice Lane, Dartmouth	48H	140	647	0.082	Bushing	7	31-Dec-11

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Porters Lake	4496 Hwy #7	126H	360	647	0.212	Bushing	18	31-Dec-10
Sackville	Next To 242 Bicentennial Hwy (South of Rifle Range)	90H	1340	647	0.789	Bushing	67	31-Dec-10
			300	647	0.177	CT	3	31-Dec-10
			1000	647	0.589	PT	10	31-Dec-10
			440	647	0.259	Bushing	22	31-Dec-11
			140	647	0.082	Bushing	7	31-Dec-13
			80	647	0.047	Bushing	4	31-Dec-14
			5	647	0.003	Cap Bank	1	31-Dec-13
			600	647	0.353	PT	6	31-Dec-11
			300	647	0.177	PT	3	31-Dec-13
Spryfield	13 Sussex Street, Spryfield	20H	140	647	0.082	Bushing	7	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-13
Tidewater Hydro	Next To 5546 Hwy #3, St. Margaret's Bay	92H	420	647	0.247	Bushing	21	31-Dec-10
Tufts Cove	315 Windmill Road, Dartmouth	91H	1180	647	0.695	Bushing	59	31-Dec-10
			700	647	0.412	PT	7	31-Dec-10
			360	647	0.212	Bushing	18	31-Dec-11
			1300	647	0.765	Bushing	65	31-Dec-12
			940	647	0.553	Bushing	47	31-Dec-13
			140	647	0.082	Bushing	7	31-Dec-14

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			1900	647	1.119	PT	19	31-Dec-11
			100	647	0.059	PT	1	31-Dec-12
			900	647	0.530	PT	9	31-Dec-13
			300	647	0.177	PT	3	31-Dec-14
V G Hospital	Across From 5778 South Street, Halifax	10H	140	647	0.082	Bushing	7	31-Dec-11
			140	647	0.082	Bushing	7	31-Dec-13
Water Street	1233 Lower Water Street, Halifax	1H	280	647	0.165	Bushing	14	31-Dec-14
			10	647	0.006	Cap Bank	2	31-Dec-13
			600	647	0.353	PT	6	31-Dec-14
Woodlawn Darmouth	59 Mount Edward Road, Dartmouth	40H	480	647	0.283	Bushing	24	31-Dec-10
			120	647	0.071	Bushing	6	31-Dec-11
			140	647	0.082	Bushing	7	31-Dec-14
Yale Street	6249 Yale Street, Halifax	9H	140	647	0.082	Bushing	7	31-Dec-14
Northeast Region								
Abercrombi e	2016 Granton, Abercrombie Drive, Abercrombie	54N	200	647	0.118	PT	2	31-Dec-10
			100	647	0.059	CT	1	31-Dec-14
Black River Road	45-38.074N / 064-04.499W	6N	240	647	0.141	Bushing	12	31-Dec-11
			260	647	0.153	Bushing	13	31-Dec-14

Braemore	45-37.405N / 062.00.632W	6C	360	647	0.212	Bushing	18	31-Dec-11
Bridge Avenue	26 Bridge Avenue, Stellarton	62N	120	647	0.071	Bushing	6	31-Dec-12
			120	647	0.071	Bushing	6	31-Dec-13
Brookfield Wind Turbine	45-16-52N 63-15-16W	86N	120	647	0.071	Bushing	6	31-Dec-10
Brownell Avenue	45-50.258N / 064-12.625W	17N	800	647	0.471	Breaker	4	31-Dec-11
Brown's Ave	45-36.298N / 062-38.458W	57N	140	647	0.082	Bushing	7	31-Dec-14
Canso Town	45-20.246N / 060-59.923W	19C	60	647	0.035	Bushing	3	31-Dec-13
Church Street Amherst	45-49.368N / 064-11.303W	22N	120	647	0.071	Bushing	6	31-Dec-11
Cloverville	45-37.537N / 061-59.369W	7C	360	647	0.212	Bushing	18	31-Dec-14
College Sub	45-36.830N / 061-59.804W	8C	40	647	0.024	Bushing	2	31-Dec-14
Debert	45-26.411N / 063-27.187W	81N	260	647	0.153	Bushing	13	31-Dec-12
			120	647	0.071	Bushing	6	31-Dec-14
			100	647	0.059	PT	1	31-Dec-11
Dickie Brook Hydro	17 Mountain Road, Dorts Cove	24C	220	647	0.130	Bushing	11	31-Dec-10
			260	647	0.153	Bushing	13	31-Dec-11

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			140	647	0.082	Bushing	7	31-Dec-13
			300	647	0.177	PT	3	31-Dec-11
Domtar Sifto Salt	45-47.016N / 064-13.947W	75N	140	647	0.082	Bushing	7	31-Dec-11
Drummond Road	45-33.344N / 062-42.845W	519N	140	647	0.082	Bushing	7	31-Dec-14
Duchess Ave	45-37.133N / 062-37.930W	543N	120	647	0.071	Bushing	6	31-Dec-14
Durham	45- 37.425N / 062-48.401W	503N	640	647	0.377	Bushing	32	31-Dec-14
Elm Street	45-35.576N / 062-39.317W	532N	140	647	0.082	Bushing	7	31-Dec-14
Fitzpatricks Mountain Wind Turbine		85N	120	647	0.071	Bushing	6	31-Dec-10
Granville	45-34.743N / 062-38.384W	528N	240	647	0.141	Bushing	12	31-Dec-14
Guysborough Intervale		78C	120	647	0.071	Bushing	6	31-Dec-12
Haliburton	45-40.470N / 062-43.887W	56N	240	647	0.141	Bushing	12	31-Dec-11
			140	647	0.082	Bushing	7	31-Dec-12
Hickman Station	45-49.077N / 064-12.617W	19N	100	647	0.059	PT	1	31-Dec-14
Hopewell	Elgin Road (45-27.275N / 062-40.083W)	79N	100	647	0.059	PT	1	31-Dec-13
			100	647	0.059	PT	1	31-Dec-14

Canada

Indian Harbour Lake	45-08.005N / 061-52.745W	87C	120	647	0.071	Bushing	6	31-Dec-11
Joggins	45-41.655N / 064-26.179W	26N	120	647	0.071	Bushing	6	31-Dec-12
Lochaber Road	5640 Highway 7, Hillsdale	4C	680	647	0.400	Bushing	34	31-Dec-10
			300	647	0.177	PT	3	31-Dec-10
			260	647	0.153	Bushing	13	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			300	647	0.177	PT	3	31-Dec-12
Lourdes	45-34.551N / 062-39.334W	64N	140	647	0.082	Bushing	7	31-Dec-14
Maccan	431 Harrison Lake Road Lower MacCain	30N	280	647	0.165	Bushing	14	31-Dec-10
			120	647	0.071	Bushing	6	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			120	647	0.071	Bushing	6	31-Dec-13
			40	647	0.024	Bushing	2	31-Dec-14
			300	647	0.177	CT	3	31-Dec-11
			300	647	0.177	CT	3	31-Dec-12
			100	647	0.059	CVT	1	31-Dec-11
			100	647	0.059	CVT	1	31-Dec-12
			100	647	0.059	PT	1	31-Dec-11

Malay Falls Hydro	307 Lochaber Mines Road, Maley Falls	95H	120	647	0.071	Bushing	6	31-Dec-12
			300	647	0.177	PT	3	31-Dec-11
Mobile 3P	not applicable	3P	220	647	0.130	Bushing	11	31-Dec-11
Northport	45-55.691N / 063-52.146W	647N	240	647	0.141	Bushing	12	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-14
Old Debert	45-26.053N / 063-27.203W	5N	120	647	0.071	Bushing	6	31-Dec-11
			140	647	0.082	Bushing	7	31-Dec-14
Onslow 138/69kV	92 Meeting House Road, Onslow	1N	600	647	0.353	Breaker	3	31-Dec-10
			180	647	0.106	Bushing	9	31-Dec-10
			2200	647	1.295	CT	22	31-Dec-10
			300	647	0.177	PT	3	31-Dec-10
			1200	647	0.707	Breaker	6	31-Dec-12
			1100	647	0.648	Bushing	55	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			200	647	0.118	Bushing	10	31-Dec-14
			5	647	0.003	Cap Bank	1	31-Dec-11
			400	647	0.236	CT	4	31-Dec-11
			100	647	0.059	CVT	1	31-Dec-12
			100	647	0.059	CVT	1	31-Dec-13
			100	647	0.059	CVT	1	31-Dec-14

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			300	647	0.177	PT	3	31-Dec-11
			100	647	0.059	PT	1	31-Dec-12
			300	647	0.177	PT	3	31-Dec-13
Onslow EHV	133 Old Tatamagouche Road, Onslow	67N	80	647	0.047	Bushing	4	31-Dec-10
			2000	647	1.178	CVT	20	31-Dec-10
			200	647	0.118	Bushing	10	31-Dec-11
			360	647	0.212	Bushing	16	31-Dec-14
			300	647	0.177	CT	3	31-Dec-11
			1500	647	0.883	CT	15	31-Dec-12
			900	647	0.530	CT	9	31-Dec-14
			700	647	0.412	PT	7	31-Dec-11
			600	647	0.353	PT	6	31-Dec-14
Oxford Junction	45-41.778N / 063-53.121W	3N	200	647	0.118	Bushing	10	31-Dec-11
Park Street	45-49.265N / 064-12.625W	20N	240	647	0.141	Bushing	12	31-Dec-11
			60	647	0.035	Bushing	3	31-Dec-12
Parrsboro	Prospect Street (45-25.552N / 064-19.155W)	37N	420	647	0.247	Bushing	21	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
Pictou Town	Palmerston Road, Pictou (45-40.949N / 062-42.574W)	55N	140	647	0.082	Bushing	7	31-Dec-14

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Powell Road		535N	360	647	0.212	Bushing	18	31-Dec-13
Pugwash	2825 Crowley Road, Pugwash	7N	80	647	0.047	Bushing	4	31-Dec-10
			240	647	0.141	Bushing	12	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-14
River Hebert	45-41.687N / 064-22.604W	65N	260	647	0.153	Bushing	13	31-Dec-14
River John Wind Turbine		88N	120	647	0.071	Bushing	6	31-Dec-10
Ruth Falls Hydro	116 Ruth Falls Road, Sheet Harbour	96H	120	647	0.071	Bushing	6	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-11
			140	647	0.082	Bushing	7	31-Dec-12
			20	647	0.012	Bushing	1	31-Dec-14
			300	647	0.177	PT	3	31-Dec-13
South Lochaber	45-23.000N / 062-02.427W	514C	120	647	0.071	Bushing	6	31-Dec-13
			140	647	0.082	Bushing	7	31-Dec-14
Springhill	83 Salt Springs Road, Salt Spring Station	74N	120	647	0.071	Bushing	6	31-Dec-10
			120	647	0.071	Bushing	6	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-14

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			100	647	0.059	CVT	1	31-Dec-11
			200	647	0.118	CVT	2	31-Dec-12
Springhill Wind Turbine	45-36-64N 64-01-80W	83N	120	647	0.071	Bushing	6	31-Dec-10
Stewiacke	45-08.971N / 063-21.103W	16N	40	647	0.024	Bushing	2	31-Dec-10
			220	647	0.130	Bushing	11	31-Dec-12
Tatamagouche	45-42.734N / 063-18.500W	4N	240	647	0.141	Bushing	12	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-13
Toney River	45-45.051N / 062-53.965W	512N	780	647	0.459	Bushing	39	31-Dec-14
Trafalgar	45-17.480N / 062-39.334W	89H	100	647	0.059	Bushing	5	31-Dec-10
			100	647	0.059	Bushing	5	31-Dec-11
			40	647	0.024	Bushing	2	31-Dec-13
Trenton Generating Station	45-37.342N / 062-38.911W	50N	600	647	0.353	Breaker	3	31-Dec-10
			660	647	0.389	Bushing	33	31-Dec-10
			400	647	0.236	PT	4	31-Dec-10
			600	647	0.353	Breaker	3	31-Dec-11
			800	647	0.471	Bushing	40	31-Dec-11
			400	647	0.236	Bushing	20	31-Dec-12

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			360	647	0.212	Bushing	18	31-Dec-13
			600	647	0.353	CT	6	31-Dec-12
			600	647	0.353	CT	6	31-Dec-14
			100	647	0.059	CVT	1	31-Dec-11
			100	647	0.059	CVT	1	31-Dec-12
			100	647	0.059	CVT	1	31-Dec-14
			300	647	0.177	PT	3	31-Dec-11
			300	647	0.177	PT	3	31-Dec-14
Upper Musquodoboit	83 Watson Hill Road, Upper Musquodoboit	88H	120	647	0.071	Bushing	6	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-13
			100	647	0.059	PT	1	31-Dec-13
Upper Stewiacke	45-13.365N / 062-59.271W	619N	140	647	0.082	Bushing	7	31-Dec-13
Whitehead	45-14.847N / 061-11.383W	516C	140	647	0.082	Bushing	7	31-Dec-14
Willow Lane Truro	347 Willow Street, Truro (45-21.386N / 063-17.620W)	15N	140	647	0.082	Bushing	7	31-Dec-12
			260	647	0.153	Bushing	13	31-Dec-14
			200	647	0.118	PT	2	31-Dec-11
Sydney Region								
Aberdeen	11541 Hwy 105, Aberdeen	9C	40	647	0.024	Bushing	2	31-Dec-11

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			100	647	0.059	Bushing	5	31-Dec-13
Albert Bridge	3898 Louisbourg Hwy, Albert Bridge	57S	240	647	0.141	Bushing	12	31-Dec-12
			60	647	0.035	Bushing	3	31-Dec-13
Arichat	Hwy 320, Arichat	10C	120	647	0.071	Bushing	6	31-Dec-12
			120	647	0.071	Bushing	6	31-Dec-13
Cape North	82 Bay St. Lawrence Road, Cape North	79S	120	647	0.071	Bushing	6	31-Dec-11
Cape Porcupine	Hwy 344, Aulds Cove	100C	300	647	0.177	Bushing	15	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-13
Cleveland	Cleveland	22C	240	647	0.141	Bushing	12	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-13
			140	647	0.082	Bushing	7	31-Dec-14
Coady Road		69C	120	647	0.071	Bushing	6	31-Dec-11
Gannon Road	82 Mapleview Drive, North Sydney	3S	240	647	0.141	Bushing	12	31-Dec-10
			360	647	0.212	Bushing	18	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			240	647	0.141	Bushing	12	31-Dec-13
			200	647	0.118	Bushing	10	31-Dec-14
			500	647	0.294	CVT	5	31-Dec-14
			300	647	0.177	PT	3	31-Dec-12

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			300	647	0.177	PT	3	31-Dec-13
Glen Tosh	4898 Hwy 105, South Haven	5S	100	647	0.059	Bushing	5	31-Dec-10
			1200	647	0.707	PT	12	31-Dec-10
			260	647	0.153	Bushing	13	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-13
Grand Etang	46-33-80N 61-02-88W	112C	120	647	0.071	Bushing	6	31-Dec-10
Keltic Drive	396 Keltic Drive, Westmount	11S	240	647	0.141	Bushing	12	31-Dec-10
			20	647	0.012	Bushing	1	31-Dec-14
Lingan 138/230 kV	2599 Hinchey Avenue, New Waterford	88S	300	647	0.177	PT	3	31-Dec-10
			200	647	0.118	Bushing	10	31-Dec-13
			200	647	0.118	Bushing	10	31-Dec-14
			300	647	0.177	PT	3	31-Dec-11
Lingan Generating Station	2599 Hinchey Avenue, New Waterford	87S	720	647	0.424	Bushing	36	31-Dec-11
			200	647	0.118	Bushing	10	31-Dec-12
Lingan Mine	2812 Hinchy Avenue, New Waterford	80S	240	647	0.141	Bushing	12	31-Dec-10
Margaree Center	Lat 46.339230 Long - 60.995577	559C	120	647	0.071	Bushing	6	31-Dec-13
Margaree Valley	Lat 46.346489 Long - 60.982469	568C	120	647	0.071	Bushing	6	31-Dec-11

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Mobile 6P	not applicable	6P	200	647	0.118	Bushing	10	31-Dec-10
			200	647	0.118	Breaker	1	31-Dec-11
New Page	120 Pulp Mill Road, Point Tupper	47C	600	647	0.353	CVT	6	31-Dec-10
			100	647	0.059	PT	1	31-Dec-10
			160	647	0.094	Bushing	8	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-13
			400	647	0.236	Bushing	20	31-Dec-14
			200	647	0.118	PT	2	31-Dec-12
			200	647	0.118	PT	2	31-Dec-13
			100	647	0.059	PT	1	31-Dec-14
New Waterford	635 Wanda Lane, New Waterford	15S	240	647	0.141	Bushing	12	31-Dec-12
Petit de Grat		14C	120	647	0.071	Bushing	6	31-Dec-13
Point Aconi Fresh Water Pump	805 Prince Mine Road, Millville	102S	60	647	0.035	Bushing	3	31-Dec-14
Point Aconi Generating Station	1800 Prince Mine Road	89S	60	647	0.035	Bushing	3	31-Dec-10
Point Tupper	4137 Port Malcolm Road, Point Tupper	1C	600	647	0.353	CT	6	31-Dec-10
			200	647	0.118	Breaker	1	31-Dec-11
			600	647	0.353	Bushing	30	31-Dec-11

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			120	647	0.071	Bushing	6	31-Dec-12
			240	647	0.141	Bushing	12	31-Dec-14
			300	647	0.177	PT	3	31-Dec-14
Point Tupper Generating Station	4137 Port Malcolm Road, Point Tupper	1C	220	647	0.130	Bushing	11	31-Dec-10
			340	647	0.200	Bushing	17	31-Dec-11
			60	647	0.035	Bushing	3	31-Dec-12
			80	647	0.047	Bushing	4	31-Dec-14
Point Tupper Wind Turbine	45-34-80N 61-20-24W	117C	120	647	0.071	Bushing	6	31-Dec-10
Port Caledonia Wind Turbine	46-11-49N 59-53-37W	108S	120	647	0.071	Bushing	6	31-Dec-10
Port Hastings	257 Hwy 105, Port Hastings	2C	280	647	0.165	Bushing	14	31-Dec-10
			300	647	0.177	CT	3	31-Dec-10
			900	647	0.530	CVT	9	31-Dec-10
			400	647	0.236	St. Service TRN	2	31-Dec-10
			1200	647	0.707	Bushing	60	31-Dec-11
			140	647	0.082	Bushing	7	31-Dec-12

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			260	647	0.153	Bushing	13	31-Dec-13
			180	647	0.106	Bushing	9	31-Dec-14
			600	647	0.353	CT	6	31-Dec-11
			300	647	0.177	CT	3	31-Dec-13
			100	647	0.059	CVT	1	31-Dec-11
			400	647	0.236	CVT	4	31-Dec-12
			700	647	0.412	PT	7	31-Dec-11
			100	647	0.059	PT	1	31-Dec-12
Reserve Street	214 Reserve Street, Glace Bay	81S	120	647	0.071	Bushing	6	31-Dec-11
			140	647	0.082	Bushing	7	31-Dec-13
			140	647	0.082	Bushing	7	31-Dec-14
South Lake Wind Mill		95S	120	647	0.071	Bushing	6	31-Dec-14
Southwest Margaree	19924 Highway 19, Southwest Margree	58C	240	647	0.141	Bushing	12	31-Dec-12
			60	647	0.035	Bushing	3	31-Dec-13
Terrace Street	318 Holly Street, Sydney	6S	140	647	0.082	Bushing	7	31-Dec-10
Townsend Street	239 Townsend Street, Sydney	4S	140	647	0.082	Bushing	7	31-Dec-11
			500	647	0.294	Bushing	25	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-13
			300	647	0.177	PT	3	31-Dec-11

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Victoria Junction	1054/1053 Grand Lake Road	2S	960	647	0.565	Bushing	48	31-Dec-10
			1100	647	0.648	PT	11	31-Dec-10
			1020	647	0.601	Bushing	51	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			240	647	0.141	Bushing	12	31-Dec-13
			420	647	0.247	Bushing	21	31-Dec-14
			300	647	0.177	CT	3	31-Dec-11
			300	647	0.177	CT	3	31-Dec-13
			200	647	0.118	CVT	2	31-Dec-11
			100	647	0.059	CVT	1	31-Dec-13
			100	647	0.059	CVT	1	31-Dec-14
			300	647	0.177	PT	3	31-Dec-13
			400	647	0.236	PT	4	31-Dec-14
Victoria Junction Distribution	1047 Grand Lake Road	84S	60	647	0.035	Bushing	3	31-Dec-11
Victoria Junction G.T.	1075 Grand Lake Road	83S	120	647	0.071	Bushing	6	31-Dec-11
Whitney Pier	515 Lingan Road, Sydney	82S	60	647	0.035	Bushing	3	31-Dec-11
Whycocomagh	103 Hwy 252, Whycocomagh	67C	120	647	0.071	Bushing	6	31-Dec-10
			300	647	0.177	PT	3	31-Dec-10

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			180	647	0.106	Bushing	9	31-Dec-11
			240	647	0.141	Bushing	12	31-Dec-12
			240	647	0.141	Bushing	12	31-Dec-13
			600	647	0.353	CT	6	31-Dec-11
Woodbine	1510 Morley Road, Sandfield	101S	400	647	0.236	PT	4	31-Dec-11
			100	647	0.059	PT	1	31-Dec-13
Wreck Cove Hydro	42338 Cabot Trail, Birch Plains	85S	380	647	0.224	Bushing	19	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-13
			200	647	0.118	CVT	2	31-Dec-14
			300	647	0.177	PT	3	31-Dec-11
			100	647	0.059	PT	1	31-Dec-13
			100	647	0.059	PT	1	31-Dec-14
West Region - Valley								
Acadia University	79 University Avenue, Wolfville	45V	120	647	0.071	Bushing	6	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-13
Annapolis Royal Hydro	236 Prince Albert Road, Annapolis	81V	60	647	0.035	Bushing	3	31-Dec-10
			100	647	0.059	PT	1	31-Dec-10
			80	647	0.047	Bushing	4	31-Dec-14

Canada

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Avon No. 1 Hydro Station	2819 Hwy 14, Vaughan	1V	240	647	0.141	Bushing	12	31-Dec-10
Bridgetown Rural	288 Brickyard Rd. Bridgetown	70V	240	647	0.141	Bushing	12	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-13
Canaan Road	1107 White Rock Road, White Rock	43V	600	647	0.353	Breaker	3	31-Dec-10
			360	647	0.212	Bushing	18	31-Dec-10
			300	647	0.177	CT	3	31-Dec-10
			200	647	0.118	PT	2	31-Dec-10
			160	647	0.094	Bushing	8	31-Dec-11
			300	647	0.177	CT	3	31-Dec-11
			300	647	0.177	CT	3	31-Dec-12
			300	647	0.177	PT	3	31-Dec-11
Conway	59 Flat Iron Road, Conway	77V	140	647	0.082	Bushing	7	31-Dec-11
			480	647	0.283	Bushing	24	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-14
			300	647	0.177	CT	3	31-Dec-14
Cornwallis	Cornwallis Industrial Park, Cornwallis	74V	120	647	0.071	Bushing	6	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-11
East Ferry	East Ferry	509V	240	647	0.141	Bushing	12	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-14

Canada

Environment Canada Environnement Canada

Falmouth	1370 Bog Road, Falmouth	35V	120	647	0.071	Bushing	6	31-Dec-10
			260	647	0.153	Bushing	13	31-Dec-13
Five Points	155 Rand Street, Hantsport	20V	320	647	0.188	Bushing	16	31-Dec-10
			260	647	0.153	Bushing	13	31-Dec-14
			300	647	0.177	CT	3	31-Dec-14
			300	647	0.177	PT	3	31-Dec-11
			100	647	0.059	PT	1	31-Dec-14
Fourth Lake Hydro	Fourth Lake	91V	100	647	0.059	CVT	1	31-Dec-14
Greenwood Village	682 Central Avenue, Greenwood	64V	360	647	0.212	Bushing	18	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-14
Gulch Hydro	143 River Road, Bear River	13V	160	647	0.094	Bushing	8	31-Dec-10
			120	647	0.071	Bushing	6	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-13
			140	647	0.082	Bushing	7	31-Dec-14
Hells's Gate Hydro	109 Hells Gate Road, White Rock	3V	140	647	0.082	Bushing	7	31-Dec-10
			200	647	0.118	PT	2	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-14
			300	647	0.177	CT	3	31-Dec-14
Hillaton	1250 Saxon Street, Hillaton	36V	240	647	0.141	Bushing	12	31-Dec-10

Canada

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			140	647	0.082	Bushing	7	31-Dec-12
Hollow Bridge Hydro	1919 Black River Road White Rock	6V	140	647	0.082	Bushing	7	31-Dec-12
Kentville	Exibition Street, Kentville	652V	140	647	0.082	Bushing	7	31-Dec-14
Kingston	430 Markland Road, Kingston	63V	360	647	0.212	Bushing	18	31-Dec-11
Lequille Hydro	470 Dugway Road, Lequille	12V	360	647	0.212	Bushing	18	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-13
			140	647	0.082	Bushing	7	31-Dec-14
			300	647	0.177	PT	3	31-Dec-12
Little Brook Wind Turbine	44-17-68N 66-05-08W	94V	120	647	0.071	Bushing	6	31-Dec-10
Lumsden Hydro	2607 Black River Road, White Rock	5V	60	647	0.035	Bushing	3	31-Dec-10
			300	647	0.177	CT	3	31-Dec-10
			80	647	0.047	Bushing	4	31-Dec-14
Maitland Bridge	1023 Northfield Road, Maitland Bridge	76V	120	647	0.071	Bushing	6	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-14
Methals Hydro	1628 Methal's Road, White Rock	7V	20	647	0.012	Bushing	1	31-Dec-10
			120	647	0.071	Bushing	6	31-Dec-13

Canada

Environment Canada Environnement Canada

Michelin Waterville	866 Randolph Road, Waterville	92V	240	647	0.141	Bushing	12	31-Dec-10
			300	647	0.177	PT	3	31-Dec-10
			100	647	0.059	CVT	1	31-Dec-12
			100	647	0.059	CVT	1	31-Dec-14
Middleton Rural	201 Nictaux Road, Middleton	65V	140	647	0.082	Bushing	7	31-Dec-11
			360	647	0.212	Bushing	18	31-Dec-13
Minas Basin Pulp and Power	51 Williams Street, Hantsport	41V	120	647	0.071	Bushing	6	31-Dec-12
Mobile 4P	not applicable	4P	220	647	0.130	Bushing	11	31-Dec-13
Mount Pleasant Wind Turbine	44-38-20N 65-48-16W	95V	120	647	0.071	Bushing	6	31-Dec-10
New Minas	30 Minas Warehouse Road, New Minas	22V	480	647	0.283	Bushing	24	31-Dec-11
			240	647	0.141	Bushing	12	31-Dec-12
			280	647	0.165	Bushing	14	31-Dec-14
Nictaux	33 Torbrook Road, Nictaux	10V	140	647	0.082	Bushing	7	31-Dec-14
Paradise Hydro	5002 Hwy 201 Paradise	11V	600	647	0.353	Breaker	3	31-Dec-10
			100	647	0.059	PT	1	31-Dec-10
Research Station	Hwy #1 Kentville	654V	140	647	0.082	Bushing	7	31-Dec-10

Canada

Ridge Hydro	660 Ridge Road, Greenland	14V	140	647	0.082	Bushing	7	31-Dec-13
Saulnierville	255 Saulnierville Road	93V	140	647	0.082	Bushing	7	31-Dec-10
			240	647	0.141	Bushing	12	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
Sissiboo Hydro	2525 Weymouth Falls Road, Weymouyh Falls	15V	240	647	0.141	Bushing	12	31-Dec-13
			380	647	0.224	Bushing	19	31-Dec-14
			100	647	0.059	CVT	1	31-Dec-13
St Croix	110 Salmon Hole Dam Road, St. Croix	17V	680	647	0.400	Bushing	34	31-Dec-10
			5	647	0.003	Cap Bank	1	31-Dec-10
			200	647	0.118	CT	2	31-Dec-10
			700	647	0.412	PT	7	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-13
			400	647	0.236	CT	4	31-Dec-13
			100	647	0.059	CVT	1	31-Dec-11
Three Mile Plains	80 Mountain Road, Three Mile Plains	79V	360	647	0.212	Bushing	18	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-14
Tremont	986 Meadowvale Road, Lot A, Tremont	51V	40	647	0.024	Bushing	2	31-Dec-10
			300	647	0.177	PT	3	31-Dec-10
			260	647	0.153	Bushing	13	31-Dec-12

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			160	647	0.094	Bushing	8	31-Dec-13
			100	647	0.059	CT	1	31-Dec-12
			300	647	0.177	PT	3	31-Dec-11
			100	647	0.059	PT	1	31-Dec-14
Upper Burlington	63 North River Road, Upper Burlington	18V	360	647	0.212	Bushing	18	31-Dec-11
Waterville	5382 Hwy 1 Waterville	55V	620	647	0.365	Bushing	31	31-Dec-13
			140	647	0.082	Bushing	7	31-Dec-14
Weymouth	46 Pulp Mill Road, Weymouth	16V	360	647	0.212	Bushing	18	31-Dec-10
			280	647	0.165	Bushing	14	31-Dec-13
			280	647	0.165	Bushing	14	31-Dec-14
White Rock	3486 Black River Road, White Rock	4V	120	647	0.071	Bushing	6	31-Dec-12
Wolfville Ridge	1582 Ridge Road, Wolfville	83V	360	647	0.212	Bushing	18	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-12
West Region - South Shore								
Auburndale	584 Auburndale (Wileville)	73W	380	647	0.224	Bushing	19	31-Dec-12
Barrington Passage	3672 Hwy 3, Barrington	22W	120	647	0.071	Bushing	6	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			260	647	0.153	Bushing	13	31-Dec-13

Canada

Environment Canada Environnement Canada

Big Falls No. 3 Hydro	117 Fish Hatchery Road, Milton	3W	500	647	0.294	Bushing	25	31-Dec-10
			400	647	0.236	PT	4	31-Dec-10
			60	647	0.035	Bushing	3	31-Dec-12
			40	647	0.024	Bushing	2	31-Dec-14
			100	647	0.059	PT	1	31-Dec-11
Bridgewater 230/138/69 kV	1627 King St., Bridgewater	99W	320	647	0.188	Bushing	16	31-Dec-10
			800	647	0.471	CT	8	31-Dec-10
			200	647	0.118	CVT	2	31-Dec-10
			200	647	0.118	Bushing	10	31-Dec-14
			200	647	0.118	CT	2	31-Dec-13
			300	647	0.177	PT	3	31-Dec-11
			400	647	0.236	St. Service TRN	2	31-Dec-14
Bridgewater East	2259 Hwy 325, Oakhill	89W	120	647	0.071	Bushing	6	31-Dec-10
			360	647	0.212	Bushing	18	31-Dec-12
Bridgewater High Street	59 High Street, Bridgewater	70W	480	647	0.283	Bushing	24	31-Dec-10
			240	647	0.141	Bushing	12	31-Dec-11
			240	647	0.141	Bushing	12	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-14
Broad River	7906 Hwy 103, Broad	46W	140	647	0.082	Bushing	7	31-Dec-11

Canada

	River							
			240	647	0.141	Bushing	12	31-Dec-12
Caledonia	9723 Hwy 8, Caledonia	57W	240	647	0.141	Bushing	12	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-13
			300	647	0.177	CT	3	31-Dec-13
Carleton Yarmouth	3663 Hwy 340	92W	120	647	0.071	Bushing	6	31-Dec-10
			260	647	0.153	Bushing	13	31-Dec-11
Central Argyle	5092 Hwy 3, Argyle	19W	60	647	0.035	Bushing	3	31-Dec-10
			80	647	0.047	Bushing	4	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			120	647	0.071	Bushing	6	31-Dec-13
Clyde River	99 Quinns Falls	23W	240	647	0.141	Bushing	12	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-13
Cowie Falls No. 6 Hydro	556 Main Street, Hwy 8, Milton	6W	60	647	0.035	Bushing	3	31-Dec-10
			60	647	0.035	Bushing	3	31-Dec-11
Deep Brook No. 5 Hydro	236 River Road, Milton	5W	40	647	0.024	Bushing	2	31-Dec-10
			80	647	0.047	Bushing	4	31-Dec-12
Green Harbour	3919 Hwy 3, East Green Harbour	36W	120	647	0.071	Bushing	6	31-Dec-12
			260	647	0.153	Bushing	13	31-Dec-13

Environment Canada Environnement Canada

Harmony Hydro	69 McGowan Lake Road, Westfield	7W	120	647	0.071	Bushing	6	31-Dec-14
Hebron	222 Hwy 3, Hebron	16W	120	647	0.071	Bushing	6	31-Dec-12
			120	647	0.071	Bushing	6	31-Dec-13
Hubbards	389 Mill Lake Road	87W	120	647	0.071	Bushing	6	31-Dec-11
			240	647	0.141	Bushing	12	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-14
			200	647	0.118	CT	2	31-Dec-12
Indian Path	628 Indian Path Road	80W	180	647	0.106	Bushing	9	31-Dec-10
			120	647	0.071	Bushing	6	31-Dec-12
			120	647	0.071	Bushing	6	31-Dec-13
			80	647	0.047	Bushing	4	31-Dec-14
King Street	12 King Street, Yarmouth	11W	360	647	0.212	Bushing	18	31-Dec-10
			200	647	0.118	Bushing	10	31-Dec-11
Lockeport	48 Upper Water Street, Lockeport	37W	120	647	0.071	Bushing	6	31-Dec-11
			240	647	0.141	Bushing	12	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-13
Lower East Pubnico	250 Hwy 3, Lower East Pubnico	20W	260	647	0.153	Bushing	13	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			300	647	0.177	CT	3	31-Dec-11

Canada

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Lower Wood's Harbour	6466 Hwy 3, Lower Woods Harbour	21W	140	647	0.082	Bushing	7	31-Dec-11
Mahone Bay Sub&Tap	60 School Street, Mahone Bay	76W	140	647	0.082	Bushing	7	31-Dec-14
Martins Brook	110 Schnare's Crossing Road, Fauxburg	78W	240	647	0.141	Bushing	12	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-14
Middlefield Distribution	4595 Hwy 8, Middlefield	91W	60	647	0.035	Bushing	3	31-Dec-10
			120	647	0.071	Bushing	6	31-Dec-12
			80	647	0.047	Bushing	4	31-Dec-13
Milton	638 Main Street, Hwy 8, Milton	50W	120	647	0.071	Bushing	6	31-Dec-10
			300	647	0.177	CT	3	31-Dec-10
			300	647	0.177	CVT	3	31-Dec-10
			300	647	0.177	PT	3	31-Dec-10
			360	647	0.212	Bushing	18	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			560	647	0.330	Bushing	28	31-Dec-13
			400	647	0.236	PT	4	31-Dec-11
			300	647	0.177	PT	3	31-Dec-12
			300	647	0.177	PT	3	31-Dec-14
Mobile 2P	not applicable	2P	80	647	0.047	Bushing	4	31-Dec-10

Canada

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			80	647	0.047	Bushing	4	31-Dec-11
Ohio Road Shelburne	261 Ohio Road, Shelburne	25W	500	647	0.294	Bushing	25	31-Dec-11
Pleasant Street Yarmouth	245 Pleasant Street, Yarmouth	88W	480	647	0.283	Bushing	24	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
Robinson Corner	4426 Hwy 3, Marriotts Cove	84W	240	647	0.141	Bushing	12	31-Dec-10
			140	647	0.082	Bushing	7	31-Dec-14
Souriquois	939 Woodlawn Drive	30W	300	647	0.177	PT	3	31-Dec-10
			240	647	0.141	Bushing	12	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			160	647	0.094	Bushing	8	31-Dec-14
			300	647	0.177	CT	3	31-Dec-11
			100	647	0.059	CVT	1	31-Dec-14
			400	647	0.236	PT	4	31-Dec-12
Tusket Distribution	8658 Hwy 3, Tusket	102W	120	647	0.071	Bushing	6	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-12
			140	647	0.082	Bushing	7	31-Dec-14
Tusket Gas Turbine	8658 Hwy 3, Tusket	10W	140	647	0.082	Bushing	7	31-Dec-11

Canada

Environment Canada Environnement Canada

Tusket Hydro & SW STA	51 Bennies Lane, Tusket Falls	9W	120	647	0.071	Bushing	6	31-Dec-10
			300	647	0.177	PT	3	31-Dec-10
			240	647	0.141	Bushing	12	31-Dec-11
			380	647	0.224	Bushing	19	31-Dec-12
			480	647	0.283	Bushing	24	31-Dec-13
			320	647	0.188	Bushing	16	31-Dec-14
			5	647	0.003	Cap Bank	1	31-Dec-11
			100	647	0.059	CVT	1	31-Dec-14
			400	647	0.236	PT	4	31-Dec-11
			100	647	0.059	PT	1	31-Dec-14
Upper Lake Falls No.1 Hydro	4347 River Road, Milton	1W	60	647	0.035	Bushing	3	31-Dec-10
Waterloo Street	278 Waterloo Street, Liverpool	48W	220	647	0.130	Bushing	11	31-Dec-14
Westhavers Elbow	1090 Hwy 325, Maitland	75W	320	647	0.188	Bushing	16	31-Dec-11
			120	647	0.071	Bushing	6	31-Dec-13
			600	647	0.353	CT	6	31-Dec-11
			100	647	0.059	CVT	1	31-Dec-14
			600	647	0.353	PT	6	31-Dec-11
2183 Gottingen Street								

Canada

Environment Canada Environnement Canada

NA	2183 Gottingen Street, Halifax	CS431-341-8903F4247-019	110	647	0.065	Transformer	1	31-Dec-10
NA	2183 Gottingen Street, Halifax	CS431-341-8903F4247-028	110	647	0.065	Transformer	1	31-Dec-10
NA	2183 Gottingen Street, Halifax	CS431-341-8903F4247-062	110	647	0.065	Transformer	1	31-Dec-10
Totals			**157775**		**92.893**		**5194**	

* An average PCB concentration of 647 mg/kg was used and is based on thePCB concentration of known PCB contaminated equipment.

** density = 0.91 kg/

Canada

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Canada

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April 26, 2010

Ms. Carolyne Blain
Director, Waste Reduction and Management Division
Environment Canada
351 St. Joseph Boulevard, 14th floor
Gatineau, Quebec
K1A 0H3

Dear Ms. Blain

RE: NSPI Authorization to Extend the 2009 End of Use Date for PCB – File Number 09/062/EXT

Nova Scotia Power Incorporated (NSPI) has received Environment Canada's authorization to extend the December 31, 2009 end of use date for specific potential PCB equipment. The equipment included in the authorization is located in substations in such a way that makes it extremely impractical to easily or immediately isolate and test substation electrical equipment. In addition, the equipment that must be tested and potentially replaced is engineered to order and typically requires six to twelve month lead time to procure.

The authorization provided by Environment Canada assigned end of use dates based on our PCB testing plan. With a total of 5194 units to test and the ongoing realities of our business operations, some adjustments in the exact testing times will be required. Therefore, NSPI is requesting a modification to the authorization issued by Environment Canada to allow a planned replacement of any equipment confirmed to contain a PCB concentration of 500 mg/kg or more by December 31, 2014.

NSPI is requesting that the authorization includes a required testing date (slightly adjusted annually to deal with real world circumstances encountered) and a final end of use date of December 31, 2014 as indicated in the table below.

Number of Pieces of Equipment	Testing Date	End of Use date
1144	December 31, 2010	December 31, 2014
1063	December 31, 2011	December 31, 2014
992	December 31, 2012	December 31, 2014
990	December 31, 2013	December 31, 2014
1005	December 31, 2014	December 31, 2014
Total - 5194		

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NSPI would update the actual status of testing and replacement on an annual basis as required by the process. This modified plan will sufficiently demonstrate significant progress towards a December 31, 2014 end of use date and will allow flexibility to test equipment and procure replacement equipment.

We are available to further discuss this request and/or answer any related questions you may have. You can contact me at (902) 428-6744 or email at terry.toner@nspower.ca.

Sincerely,

Terry Toner
Director, Environmental Services

Total Number of items to be sampled

Device Type	Total Devices
Breaker	9
Bushing	271
CT	6
CVT	2
Light Ballast	1
Pole Top Transformer	109
PT	24
Recloser	17
Regulator	1
St. Service TRN	12
Station Service Transformer	1
Transformer	12
Grand Total	**465**

Yearly Sampling Expected

Year	Total Expected Number of Devices to be Sampled
2016	59
2017	58
2018	58
2019	58
2020	58
2021	58
2022	58
2023	58
Grand Total	**465**

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Total Number of items to be Replaced

Device Type	Total to Replace
Breaker	96
Bushing (Breaker)	11
Bushing (Transformer)	304
CT	3
CVT	6
Pole Top Transformer	2
PT	17
St. Service TRN	1
Tapchanger	1
Transformer	2
Grand Total	**443**

Yearly Replacement Expected

Year	Total Expected Number of Devices to be Replaced
2016	56
2017	56
2018	56
2019	55
2020	55
2021	55
2022	55
2023	55
Grand Total	**443**

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Equipment	Region	Substation Location	Device ID	Voltage	Main Tank	Bushing #1	Bushing #2	Bushing #3	Bushing #4	Bushing #5	Bushing #6
Breaker	Sydney	Point Tupper	1C-680	138kv	<1	79	72	Sample Port Siezed	79	78	70
Breaker	Sydney	Point Tupper	1C-685	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	Point Tupper	1C-687	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	Point Tupper	1C-689	138kv	1	440	Sample Port Siezed	Sample Port Siezed	140	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	Point Tupper	1C-690	138kv	8	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	Point Tupper	1C-691	138kv	1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	Port Hastings	2C-643	138kv	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015
Breaker	Sydney	Port Hastings	2C-648	138kv	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015
Breaker	Sydney	Victoria Junction	2S-500	69kv	2	180	260	230	240	180	220
Breaker	Sydney	Victoria Junction	2S-501	69kv	2	77	78	85	77	82	95
Breaker	Sydney	Victoria Junction	2S-502	69kv	3	310	280	560	250	260	250
Breaker	Sydney	Victoria Junction	2S-503	69kv	1	73	73	78	78	73	75
Breaker	Sydney	Victoria Junction	2S-504	69kv	13	300	380	390	360	400	360
Breaker	Sydney	Victoria Junction	2S-505	69kv	<1	39	350	320	340	350	340
Breaker	Sydney	Victoria Junction	2S-506	69kv	1	68	65	68	64	71	69
Breaker	Sydney	Victoria Junction	2S-513	69kv	8	67	70	72	71	73	140
Breaker	Sydney	Victoria Junction	2S-531	69kv	<1	290	290	280	400	300	220
Breaker	Sydney	Victoria Junction	2S-532	69kv	<1	240	310	160	250	240	250
Breaker	Sydney	Victoria Junction	2S-600	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	Victoria Junction	2S-601	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	120	Sample Port Siezed
Breaker	Sydney	Victoria Junction	2S-602	138kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Sydney	Victoria Junction	2S-603	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	Victoria Junction	2S-604	138kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Sydney	Victoria Junction	2S-607	138kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Sydney	Victoria Junction	2S-608	138kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Sydney	Gannon Road	3S-517	69kv	5	61	64	8.3	61	44	8.8
Breaker	Sydney	Gannon Road	3S-518	69kv	13	74	66	71	72	72	67
Breaker	Sydney	Gannon Road	3S-523	69kv	4	60	65	60	82	72	64
Breaker	Sydney	Gannon Road	3S-628	138kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Sydney	Gannon Road	3S-629	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	New Page	47C-673	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	New Page	47C-674	138kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Sydney	New Page	47C-675	138kv	15	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	Glen Tosh	5S-604	138kv	<1	20	22	Sample Port Siezed	20	21	21
Breaker	Sydney	Glen Tosh	5S-606	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	Glen Tosh	5S-607	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Sydney	Glen Tosh	5S-608	138kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Sydney	Whycocomagh	67C-559	69kv	<1	62	59	47	60	62	47
Breaker	Northeast	Onslow 138/69kV	1N-521	69kv	3	82	83	78	77	84	85
Breaker	Northeast	Onslow 138/69kV	1N-522	69kv	3	74	100	90	83	81	85
Breaker	Northeast	Maccan	30N-548	69kv	<1	65	66	55	61	67	69
Breaker	Northeast	Maccan	30N-549	69kv	<1	350	340	360	320	320	370
Breaker	Northeast	Lochaber Road	4C-532	69kv	<1	75	81	81	75	77	75
Breaker	Northeast	Lochaber Road	4C-533	69kv	<1	84	78	73	76	76	83
Breaker	Northeast	Lochaber Road	4C-620	138kv	1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	370	Sample Port Siezed	Sample Port Siezed
Breaker	Northeast	Lochaber Road	4C-621	138kv	<1	110	110	110	110	110	120
Breaker	Northeast	Lochaber Road	4C-622	138kv	1	140	150	130	210	140	130
Breaker	Northeast	Lochaber Road	4C-623	138kv	<1	200	200	190	200	Sample Port Siezed	180
Breaker	Northeast	Trenton Generating Station	50N-500	69kv	<1	75	83	79	81	87	86
Breaker	Northeast	Trenton Generating Station	50N-505	69kv	<1	240	240	240	230	230	210
Breaker	Northeast	Trenton Generating Station	50N-512	69kv	31	51	49	51	49	48	50
Breaker	Northeast	Trenton Generating Station	50N-606	138kv	5	Sample Port Siezed	100	98	100	100	110
Breaker	Northeast	Trenton Generating Station	50N-612	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	360	Sample Port Siezed	Sample Port Siezed
Breaker	Northeast	Trenton Generating Station	50N-614	138kv	6	51	88	93	96	97	84
Breaker	Northeast	Springhill	74N-512	69kv	<1	340	350	400	310	320	280
Breaker	Northeast	Springhill	74N-613	138kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Northeast	Springhill	74N-636	138kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Northeast	Ruth Falls Hydro	96H-512	69kv	<1	210	170	290	270	260	240
Breaker	Northeast	Ruth Falls Hydro	96H-513 (Spare)	69kv	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Metro	Lakeside	103H - 563	69kv	<1	10	65	52	53	70	64
Breaker	Metro	Kempt Road	104H - 600	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Metro	Sackville	90H - 501	69kv	<1	190	210	200	210	230	200
Breaker	Metro	Sackville	90H - 503	69kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Metro	Sackville	90H - 506	69kv	<1	83	270	240	250	340	280
Breaker	Metro	Sackville	90H - 601	138kv	<1	320	310	300	270	450	290
Breaker	Metro	Sackville	90H - 602	138kv	<1	400	Sample Port Siezed	350	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Metro	Sackville	90H - 603	138kv	<1	380	400	Sample Port Siezed	400	420	430
Breaker	Metro	Sackville	90H - 604	138kv	<1	54	58	60	59	59	49

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Equipment	Region	Substation Location	Device ID	Voltage	Main Tank	Bushing #1	Bushing #2	Bushing #3	Bushing #4	Bushing #5	Bushing #6
Breaker	Metro	Sackville	90H - 605	138kv	<1	150	160	160	150	160	170
Breaker	Metro	Sackville	90H - 606	138kv	<1	100	100	110	120	110	140
Breaker	Metro	Sackville	90H - 607	138kv	<1	47	49	51	50	52	53
Breaker	Metro	Tufts Cove	91H-608	138kv	<1	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed	Sample Port Siezed
Breaker	Metro	Tufts Cove	91H-609	138kv	<1	Could Not Sample, Replaced in 2015	Could Not Sample, Replaced in 2015	Could Not Sample, Replaced in 2015	Could Not Sample, Replaced in 2015	Could Not Sample, Replaced in 2015	Could Not Sample, Replaced in 2015
Breaker	Metro	Farrell Street	99H-506	69kv	<1	270	260	260	260	260	260
Breaker	Metro	Farrell Street	99H-510	69kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	Metro	Farrell Street	99H-513	69kv	<1	67	43	41	78	79	New Bushing
Breaker	Metro	Farrell Street	99H-514	69kv	1	190	200	200	200	200	210
Breaker	West	Souriquois	30W-507	69kv	<1	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample	Could Not Sample
Breaker	West	Souriquois	30W-508	69kv	<1	420	440	450	420	480	430
Breaker	West	Big Falls No. 3 Hydro	3W-502	69kv	1	380	370	370	350	370	340
Breaker	West	Big Falls No. 3 Hydro	3W-504	69kv	5	360	360	340	340	330	330
Breaker	West	Big Falls No. 3 Hydro	3W-511	69kv	2	220	230	230	210	220	230
Breaker	West	Milton	50W-500	69kv	<1	62	60	50	47	51	47
Breaker	West	Milton	50W-512	69kv	<1	50	54	50	51	48	48
Breaker	West	Milton	50W-600	138kv	<1	56	51	50	49	50	49
Breaker	West	Westhavers Elbow	75W-502	69kv	<1	No Sample Port	No Sample Port	No Sample Port	No Sample Port	No Sample Port	No Sample Port
Breaker	West	Tusket Hydro & SW STA	9W-500	69kv	<1	67	68	62	70	68	69
Breaker	West	Tusket Hydro & SW STA	9W-501	69kv	<1	410	370	470	370	480	360
Breaker	West	Tusket Hydro & SW STA	9W-511	69kv	<1	85	250	100	220	250	130
Breaker	West	Tusket Hydro & SW STA	9W-513	69kv	1	420	540	540	450	470	490
Breaker	West	Tusket Hydro & SW STA	9W-514	69kv	<1	81	86	88	80	72	82
Breaker	West	Tusket Hydro & SW STA	9W-515	69kv	<1	78	510	110	490	440	440
Breaker	West	Tusket Hydro & SW STA	9W-516	69kv	<1	62	68	64	69	68	64
Breaker	West	Tusket Hydro & SW STA	9W-517	69kv	2	220	200	220	210	210	210
Breaker	West	Tusket Hydro & SW STA	9W-563	69kv	1	310	280	360	320	340	330
Breaker	Valley	Sissiboo	15V-550	69kv	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015	Replaced in 2015
Breaker	Valley	Weymouth	16V-554	69kv	<1	73	72	91	75	81	88
Breaker	Valley	St Croix	17V-512	69kv	<1	62	62	61	62	59	6
Breaker	Valley	Canaan Road	43V - 504	69kv	<1	25	26	24	88	78	70
Breaker	Valley	Tremont	51V - 521	69kv	<1	70	79	74	72	69	76

Request IR-48:

Reference CI# 48114, 2016 Steel Tower Life Extension - HRM

(a) Please provide the analysis conducted that concluded to “the most cost effective approach is to recoat the steel towers” as described on page 828 of Exhibit N-1.

(b) Provide documentation that describes the process for deciding how to extend a particular steel structure lifespan. How does NPSI decide whether to recoat or to install sacrificial anodes when it seeks to extend the lifespan of a particular steel structure?

Response IR-48:

(a) Please refer to Attachment 1.

(b) The corrosion mitigation measures that are chosen for a particular steel structure are not mutually exclusive – a particular steel tower may require both recoating and sacrificial anodes. The decision to recoat and/or install sacrificial anodes on a tower depends on the location of the identified or potential corrosion. Recoating is used to protect steel towers against any corrosion above ground level and sacrificial anodes are used to protect steel towers against any corrosion below ground level. Please refer to Confidential Attachment 2 for an explanation of why sacrificial anodes are not typically used to protect above grade steel against corrosion. Please refer to Confidential Attachment 3 for an explanation how sacrificial anodes protect below grade steel against corrosion. Please refer to Confidential Attachment 4 for an explanation of the decision to recoat certain steel transmission structures.

Steel Tower Painting
Summary of Alternatives

Division :	Technical & Construction Services	**Date :**	**19-Dec-12**
Department :	T&D Engineering	**CI Number:**	43490
Originator :		**Project No. :**	

	Alternative	After Tax WACC	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Recoat Steel Towers	6.48%	-148,914	1	#NUM!	0.0 years
B	Replace Steel Towers	6.48%	-215,611	2	-10.96%	0.0 years
	0	NA	NA	NA	#VALUE!	#VALUE!
	0	NA	NA	NA	#VALUE!	#VALUE!

Recommendation :

Recoat towers to extend the life of the tower

Notes/Comments :

Recoat Steel Towers

Assume that the tower life is extended 10 years because of the painting (a conservative estimate). Assumed that the tower is currently 35 years old with a standard life of 50 years (extended if recoated). Assume the average cost to apply protective coating is $70,000 and average cost to replace a tower is approximately $500,000.

Replace Steel Towers

Assume no preventative work and tower needs to be replaced after 50 years. Assume that the tower is currently 35 years old. Average cost to replace a tower is approximately $500,000.

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Steel Tower Painting
Recoat Steel Towers

Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2013	-	-	(70,000.0)	-	-	(70,000.0)	-	(70,000.0)	(70,000.000)	1.0	(70,000.0)
2014	-	-	-	2,800.0	67,200.0	-	868.0	868.0	815.177	0.9	(69,184.8)
2015	-	-	-	5,376.0	61,824.0	-	1,666.6	1,666.6	1,469.890	0.9	(67,714.9)
2016	-	-	-	4,945.9	56,878.1	-	1,533.2	1,533.2	1,270.003	0.8	(66,444.9)
2017	-	-	-	4,550.2	52,327.8	-	1,410.6	1,410.6	1,097.298	0.8	(65,347.6)
2018	-	-	-	4,186.2	48,141.6	-	1,297.7	1,297.7	948.078	0.7	(64,399.6)
2019	-	-	-	3,851.3	44,290.3	-	1,193.9	1,193.9	819.151	0.7	(63,580.4)
2020	-	-	-	3,543.2	40,747.1	-	1,098.4	1,098.4	707.756	0.6	(62,872.6)
2021	-	-	-	3,259.8	37,487.3	-	1,010.5	1,010.5	611.510	0.6	(62,261.1)
2022	-	-	-	2,999.0	34,488.3	-	929.7	929.7	528.352	0.6	(61,732.8)
2023	-	-	(85,329.6)	9,585.4	110,232.5	(85,329.6)	2,971.5	(82,358.1)	(43,956.796)	0.5	(105,689.6)
2024	-	-	-	8,818.6	101,413.9	-	2,733.8	2,733.8	1,370.291	0.5	(104,319.3)
2025	-	-	-	8,113.1	93,300.8	-	2,515.1	2,515.1	1,183.948	0.5	(103,135.3)
2026	-	-	-	7,464.1	85,836.7	-	2,313.9	2,313.9	1,022.945	0.4	(102,112.4)
2027	-	-	-	6,866.9	78,969.8	-	2,128.8	2,128.8	883.837	0.4	(101,228.6)
2028	-	-	-	6,317.6	72,652.2	-	1,958.5	1,958.5	763.646	0.4	(100,464.9)
2029	-	-	-	5,812.2	66,840.0	-	1,801.8	1,801.8	659.799	0.4	(99,805.1)
2030	-	-	-	5,347.2	61,492.8	-	1,657.6	1,657.6	570.074	0.3	(99,235.0)
2031	-	-	-	4,919.4	56,573.4	-	1,525.0	1,525.0	492.551	0.3	(98,742.5)
2032	-	-	-	4,525.9	52,047.5	-	1,403.0	1,403.0	425.570	0.3	(98,316.9)
2033	-	-	(104,016.3)	12,485.1	143,578.7	(104,016.3)	3,870.4	(100,145.9)	(28,528.075)	0.3	(126,845.0)
2034	-	-	-	11,486.3	132,092.4	-	3,560.8	3,560.8	952.605	0.3	(125,892.4)
2035	-	-	-	10,567.4	121,525.0	-	3,275.9	3,275.9	823.062	0.3	(125,069.3)
2036	-	-	-	9,722.0	111,803.0	-	3,013.8	3,013.8	711.136	0.2	(124,358.2)
2037	-	-	-	8,944.2	102,858.8	-	2,772.7	2,772.7	614.430	0.2	(123,743.8)
2038	-	-	-	8,228.7	94,630.1	-	2,550.9	2,550.9	530.875	0.2	(123,212.9)
2039	-	-	-	7,570.4	87,059.7	-	2,346.8	2,346.8	458.682	0.2	(122,754.2)
2040	-	-	-	6,964.8	80,094.9	-	2,159.1	2,159.1	396.307	0.2	(122,357.9)
2041	-	-	-	6,407.6	73,687.3	-	1,986.4	1,986.4	342.414	0.2	(122,015.5)
2042	-	-	-	5,895.0	67,792.3	-	1,827.4	1,827.4	295.850	0.2	(121,719.6)
2043	-	-	(126,795.3)	15,567.0	179,020.6	(126,795.3)	4,825.8	(121,969.5)	(18,544.285)	0.2	(140,263.9)
2044	-	-	-	14,321.7	164,699.0	-	4,439.7	4,439.7	633.936	0.1	(139,630.0)
2045	-	-	-	13,175.9	151,523.1	-	4,084.5	4,084.5	547.728	0.1	(139,082.3)
2046	-	-	-	12,121.8	139,401.2	-	3,757.8	3,757.8	473.244	0.1	(138,609.0)
2047	-	-	-	11,152.1	128,249.1	-	3,457.2	3,457.2	408.888	0.1	(138,200.1)
2048	-	-	-	10,259.9	117,989.2	-	3,180.6	3,180.6	353.284	0.1	(137,846.8)
2049	-	-	-	9,439.1	108,550.1	-	2,926.1	2,926.1	305.242	0.1	(137,541.6)
2050	-	-	-	8,684.0	99,866.0	-	2,692.0	2,692.0	263.733	0.1	(137,277.9)
2051	-	-	-	7,989.3	91,876.8	-	2,476.7	2,476.7	227.868	0.1	(137,050.0)
2052	-	-	-	7,350.1	84,526.6	-	2,278.5	2,278.5	196.881	0.1	(136,853.1)
2053	-	-	(154,562.8)	19,127.2	219,962.2	(154,562.8)	5,929.4	(148,633.4)	(12,061.313)	0.1	(148,914.4)
Total	-	-	(540,704.0)	320,741.8		(540,704.0)	99,429.9	(441,274.1)	(148,914.4)		

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Steel Tower Painting
Replace Steel Towers

Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2013	-	-	-	-	-	-	-	-	-	1.0	-
2014	-	-	-	-	-	-	-	-	-	0.9	-
2015	-	-	-	-	-	-	-	-	-	0.9	-
2016	-	-	-	-	-	-	-	-	-	0.8	-
2017	-	-	-	-	-	-	-	-	-	0.8	-
2018	-	-	-	-	-	-	-	-	-	0.7	-
2019	-	-	-	-	-	-	-	-	-	0.7	-
2020	-	-	-	-	-	-	-	-	-	0.6	-
2021	-	-	-	-	-	-	-	-	-	0.6	-
2022	-	-	-	-	-	-	-	-	-	0.6	-
2023	-	-	-	-	-	-	-	-	-	0.5	-
2024	-	-	-	-	-	-	-	-	-	0.5	-
2025	-	-	-	-	-	-	-	-	-	0.5	-
2026	-	-	-	-	-	-	-	-	-	0.4	-
2027	-	-	-	-	-	-	-	-	-	0.4	-
2028	-	-	(672,934.2)	53,834.7	619,099.4	(672,934.2)	16,688.8	(656,245.4)	(255,885.476)	0.4	(255,885.5)
2029	-	-	-	49,528.0	569,571.5	-	15,353.7	15,353.7	5,622.422	0.4	(250,263.1)
2030	-	-	-	45,565.7	524,005.8	-	14,125.4	14,125.4	4,857.840	0.3	(245,405.2)
2031	-	-	-	41,920.5	482,085.3	-	12,995.3	12,995.3	4,197.232	0.3	(241,208.0)
2032	-	-	-	38,566.8	443,518.5	-	11,955.7	11,955.7	3,626.459	0.3	(237,581.5)
2033	-	-	-	35,481.5	408,037.0	-	10,999.3	10,999.3	3,133.304	0.3	(234,448.2)
2034	-	-	-	32,643.0	375,394.0	-	10,119.3	10,119.3	2,707.212	0.3	(231,741.0)
2035	-	-	-	30,031.5	345,362.5	-	9,309.8	9,309.8	2,339.064	0.3	(229,401.9)
2036	-	-	-	27,629.0	317,733.5	-	8,565.0	8,565.0	2,020.979	0.2	(227,381.0)
2037	-	-	-	25,418.7	292,314.8	-	7,879.8	7,879.8	1,746.151	0.2	(225,634.8)
2038	-	-	-	23,385.2	268,929.6	-	7,249.4	7,249.4	1,508.695	0.2	(224,126.1)
2039	-	-	-	21,514.4	247,415.3	-	6,669.5	6,669.5	1,303.531	0.2	(222,822.6)
2040	-	-	-	19,793.2	227,622.1	-	6,135.9	6,135.9	1,126.266	0.2	(221,696.3)
2041	-	-	-	18,209.8	209,412.3	-	5,645.0	5,645.0	973.108	0.2	(220,723.2)
2042	-	-	-	16,753.0	192,659.3	-	5,193.4	5,193.4	840.777	0.2	(219,882.4)
2043	-	-	-	15,412.7	177,246.6	-	4,778.0	4,778.0	726.441	0.2	(219,156.0)
2044	-	-	-	14,179.7	163,066.8	-	4,395.7	4,395.7	627.654	0.1	(218,528.3)
2045	-	-	-	13,045.3	150,021.5	-	4,044.1	4,044.1	542.300	0.1	(217,986.0)
2046	-	-	-	12,001.7	138,019.8	-	3,720.5	3,720.5	468.554	0.1	(217,517.5)
2047	-	-	-	11,041.6	126,978.2	-	3,422.9	3,422.9	404.836	0.1	(217,112.7)
2048	-	-	-	10,158.3	116,819.9	-	3,149.1	3,149.1	349.784	0.1	(216,762.9)
2049	-	-	-	9,345.6	107,474.3	-	2,897.1	2,897.1	302.217	0.1	(216,460.7)
2050	-	-	-	8,597.9	98,876.4	-	2,665.4	2,665.4	261.119	0.1	(216,199.5)
2051	-	-	-	7,910.1	90,966.3	-	2,452.1	2,452.1	225.610	0.1	(215,973.9)
2052	-	-	-	7,277.3	83,689.0	-	2,256.0	2,256.0	194.930	0.1	(215,779.0)
2053	-	-	-	6,695.1	76,993.9	-	2,075.5	2,075.5	168.422	0.1	(215,610.6)
Total	-	-	(672,934.2)	595,940.3		(672,934.2)	184,741.5	(488,192.7)	(215,610.6)		

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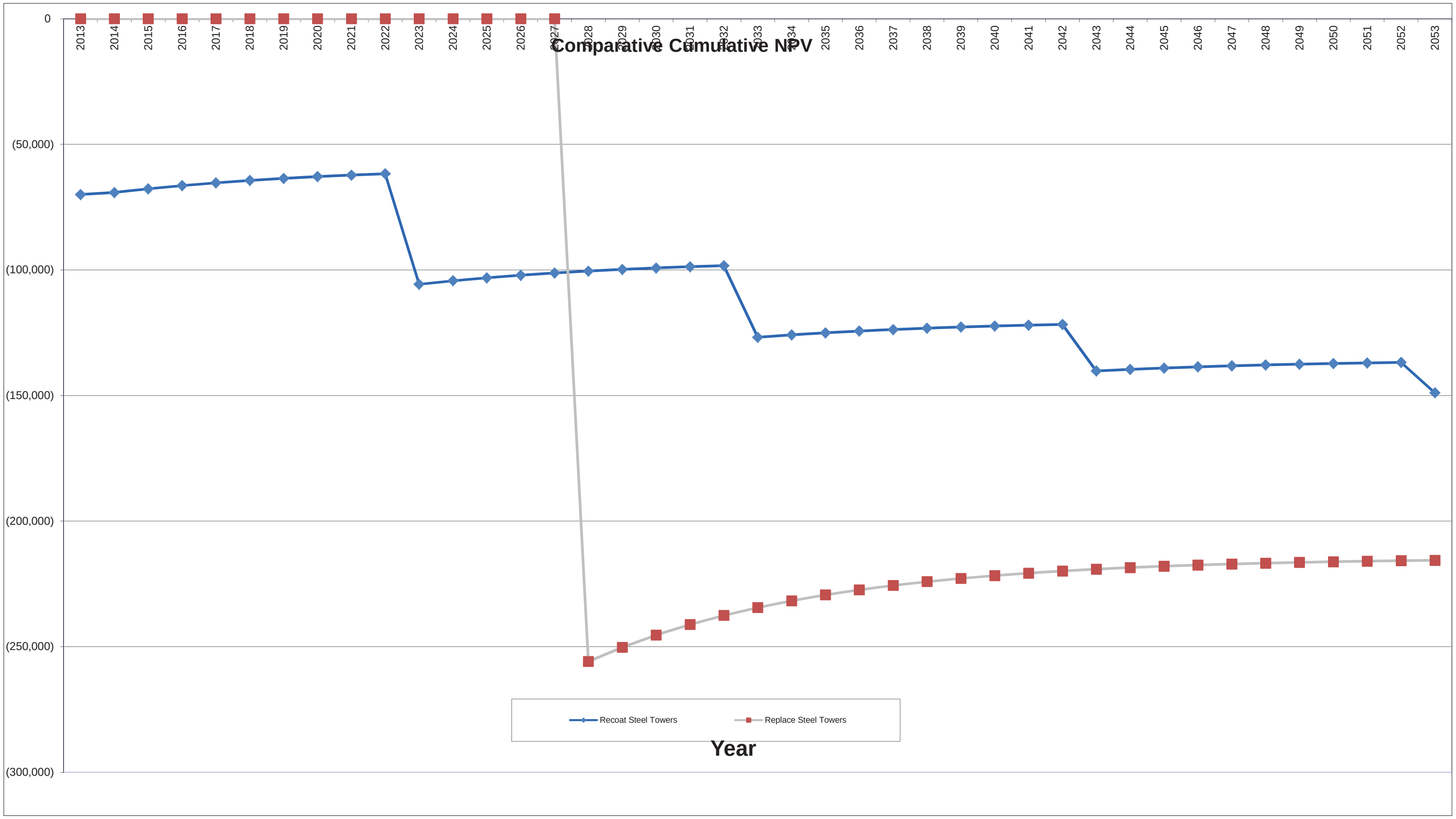

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

SBA IR-48 Attachments 2, 3 and 4 have been removed due to confidentiality.

Request IR-49:

Reference CI# 48059, 2016/2017 Transmission Switch & Breaker Replacements

(a) Please provide the instances in the last 3 years where the x69kV Breakers and 2x138kV Breakers failed.

(b) Provide a copy of the Switch & Breaker program documentation as described on page 847 of Exhibit N-1.

Response IR-49:

(a) 69kV and 138kV Breaker failures over the last 3 years are identified in the table below:

Device	Voltage (kV)	Year
74N-619	138	2013
91W-503	69	2014
2S-511	69	2014
51V-519	69	2014
4C-533	69	2015
3S-629	138	2015
2C-643	138	2015
91H-609	138	2015

(b) The program noted in CI 48059 is a collection of capital projects that are submitted annually to replace deteriorated or failed breakers and switches. The number of breakers and switches scheduled for replacement each year is dependent on the risk profile of these asset classes. The switches and breakers are ranked by risk based on a number of condition and criticality parameters:

- Maintenance History
- Age

- Operations Count
- Testing Results
- Design
- Inspection Results
- Number of Customers Served
- Equipment Redundancy
- System Impact
- Safety & Environment

REDACTED

Request IR-50:

Reference CI# 47721, 2016 PCB Phase – out for Pole transformer

(a) **On page 865 of Exhibit N-1, NSPI states the following: "The 2016 project has an increased focused (sic) on identification of PCB containing transformers through sampling, enabling the development of a strategic replacement plan." Please provide the strategic replacement plan documentation.**

(b) **Please provide documentation that confirms "The amount of testing as part of the 2016 program has been accelerated in order to take advantage of approximately 15% savings in the cost of testing" denoted on page 865 of the ACE Plan application (Exhibit N-1).**

Response IR-50:

(a) Targeted transformers are in the process of being sampled and tested. The strategic replacement plan for 2016 is being developed as oil testing results are received. The strategy is based on distributing the 10,000 targeted transformers for 2016 across the entire province, based on customer counts and resource availability. Sampling and testing results are reviewed on a regular basis to ensure the strategy will result in compliance to the regulatory requirement to have all equipment containing PCBs in concentrations at or above 50 mg/kg out of service by December 31, 2025.

(b) A significant portion of the cost associated with transformer PCB testing is the patented rivet that is used to seal the hole made in the transformer to extract the oil sample. The initial quote provided by the rivet supplier was $[redacted]/unit. The cost per rivet was negotiated down to $[redacted]/unit based on current year and future year volumes ([redacted] per year) of transformer testing. Please refer to costing scenario 3 in Partially Confidential Attachment 1, and Partially Confidential Attachment 2.

May 27, 2015

Sent via e-mail

To: **Nova Scotia Power**
PO Box 910
Halifax, NS Canada
B3J 2W5
Attention: Jill Peterson, Eli Sparks and Kathryn Richardson

From: Jaco Environmental Systems LTD.
10 – 6874 52nd Avenue
Red Deer, AB T4N 4L1, Canada
Email: Jamie@jacolinecontractors.com and/or
Christina@jacolinecontractors.com

Reference: **Three Costing Senerios for Nova Scotia Power**

1. Jaco conducts the work at a set cost of [redacted] per transformer additional cost break down as follows:

Unit Price Category	Work Activity	Unit Price (CDN $)
A	Mobilizing Fees one way	$ [redacted]
B	Testing per unit cost which includes Jaco providing Traffic Control	$ [redacted]

2. Jaco supplies the patented rivet, and patent tools for temporary rental use by the Nova Scotia Hydro Authority and Competent Training is provided by JACO.

Costs	Per Hour Price (CDN $)
Rivet Costs	= $[redacted] per Rivet (min of [redacted])
Tool Costs **(Set reference see below)**	= $[redacted] per **set**/ per month
Noodle Costs (syringe sampler)	= $[redacted]
Supply Shipping Costs	= Cost plus 15%
Training	= 0 for the 1st class arrangement training session, $[redacted] per class arrangement for any additional separate training sessions
Expenses plus 15% to provide training	= Cost plus 15% (flights, accomadations, meals, etc.

Set consists of: Drill Stick, Punch Stick, Silicone Stick, Noodle Sample Stick and Rivet Setter

Note: Signed, Legal, Confidentiality expectation for intellectual property rental agreement will be required for senerio 2.

3. Nova Scotia Power to purchase [redacted] rivets per year @ [redacted]/rivet and associated costs listed in point 2 would be included with no additional costs for the duration of your project aprox [redacted] units. Maintenance and up keep of the sticks will be handled in training and supplies provided by Jaco. Ownership of all intellectual and physical property remains with Jaco. This offer applies to only Nova Scotia Power in Nova Scotia, no competition clause will apply.

Nova Scotia POWER
An Emera Company

PURCHASE ORDER

Purchase Order No.	Revision	Page
285721	0	1

SHIP TO: NOVA SCOTIA POWER INC.
C/O: *BELL, Ms. GENOA MARINA*
25 Lakeside Park Drive
Lakeside Industrial Park
LAKESIDE,NS B3T 1M9
Canada

VENDOR — Vendor Number 1057564

JACO ENVIRONMENTAL SYSTEMS LTD
10 6874 52 AVENUE
RED DEER,AB T4N 4L1

BILL TO: NOVA SCOTIA POWER INC.
C/O ACCOUNTS PAYABLE
PO BOX 910
HALIFAX,NS B3J 2W5
Canada

DATE OF ORDER/BUYER: 24-SEP-15 L GATES
REVISED DATE/BUYER:
PAYMENT TERMS: NET 35
PROCESS/CONFIRMED TO: NSPINTERNAL (403) 348-5572
SHIP VIA:
F.O.B. DESTINATION
FREIGHT TERMS: PREPAID

ITEM	PART NUMBER / DESCRIPTION	DELIVERY DATE	QUANTITY	UNIT	UNIT PRICE	EXTENSION
	All prices and amounts on this order are expressed in: Canadian dollar					
1	Transformer Oil Sampling Program o SHIP TO: Address at top of page	PROMISED: 31-DEC-15				[redacted] Y

IMPORTANT

The terms and conditions on the reverse of this Purchase Order apply to this transaction unless specifically excepted above. ***SHIPPING DOCUMENTS & INVOICES MUST REFERENCE THE PURCHASE ORDER NUMBER.***

All amounts of Harmonized Sales Tax or Goods and Services Tax must be shown separately on each invoice along with your Tax Registration Number.

MSDS – If the material shipped on this order is classified as a "Controlled Product", a Material Safety Data Sheet (MSDS) MUST accompany the shipment.

BUYER COPY

TOTAL [redacted]

Linda Gates

AUTHORIZED SIGNATURE

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

1.0 Definitions:
In this PO, the following terms have the following meanings where the context permits or requires:
(a) "**Goods**" includes machinery, equipment, goods, materials, supplies, drawings and other property specified by NSPI in this PO.
(b) "**NSPI**" means Nova Scotia Power Incorporated, its successors and assigns.
(c) "**PO**" means this agreement/purchase order and any additional terms or conditions attached hereto.
(d) "**Seller**" means the persons, and/or corporations to which this PO is addressed and each of their respective heirs, personal representatives, successors and permitted assigns.
(e) "**Services**" means any and all services provided by the Seller to NSPI under this PO.

2.0 Entire Agreement:
This PO and any confidentiality agreement(s) entered into between NSPI and the Seller represents the entire agreement between the parties with reference to its subject matter. No modification or amendment shall be binding on either party unless consented to in writing by both parties. Each party agrees that it has not relied on any representations of the other party not contained in this PO. The terms and conditions of this PO shall supercede and abrogate all previous communications, commitments or agreements between the parties, unless a formal written agreement has been entered into between the parties.

3.0 Packaging:
NSPI will not pay any additional charges for boxing, crating, or packing, except by special agreement with the Seller.

4.0 Shipment:
Delivery must be made on the date(s) specified herein. If the Seller fails to make deliveries in accordance with this PO, NSPI may at its option terminate this PO in whole or in part and return (at the Seller's expense) or refuse to accept the Goods. Quantities received by NSPI in excess of quantities specified may, at the option of NSPI, be returned at Seller's expense.

Services must be performed by the date(s) specified herein. If the Seller fails to perform the Services in accordance with this Purchase Order, NSPI may at its option terminate this Purchase Order in whole or in part.

5.0 Inspections:
Goods are subject to inspection by NSPI. If NSPI determines that the Goods are not in accordance with specifications accompanying the PO, they may be rejected by NSPI and returned at NSPI's discretion. If inspection discloses defective Goods, or Goods of an inferior quality or workmanship, NSPI, at its option, may cancel any unshipped Goods and return the Goods at the Seller's expense.

NSPI reserves the right to appoint its own inspector, at NSPI´s cost, to inspect, examine and witness all tests on Goods. At all times, the Seller shall co–operate with NSPI's inspector.

Inspection or lack of inspection does not relieve the Seller of the Seller's obligations (including warranties) under this PO.

6.0 Title:
Title to the Goods and risk of loss shall pass from the Seller to NSPI upon delivery to and acceptance by NSPI.

7.0 Intellectual Property:
The Seller acknowledges and agrees that all contributions made in the course of provision of the Services, and namely the works, work product, drawings, innovations, discoveries, inventions or realizations, as well as their adaptation or modification, whether they be protected or not under any applicable law, entirely and solely belong to NSPI when made, conceived, created, realized or implemented by the Seller. The Seller, in advance, assigns and transfers to NSPI all right, title and interest to said contributions and work product and agrees, at NSPI´s request, to execute any documentation required to effect such transfer.

Nothing contained herein shall be construed as limiting or depriving the Seller of its right to use the general knowledge, know–how and skills developed during the provision of the Services, provided that the Seller shall remain subject to any continuing confidentiality obligations to NSPI.

8.0 Price & Payment:
Unless otherwise stated, all prices stated are in Canadian dollars. Payment shall be made net 35 days from receipt of invoice by NSPI. NSPI is not responsible for any interest or carrying charges unless consented to in writing by NSPI. The Seller will not permit any lien or charge to attach to the Goods or to any of NSPI's property or premises. If a lien or charge is attached, the Seller will promptly procure its release, and hold NSPI harmless from all loss, cost, damage or expense incidental thereto. All payments by NSPI to the Seller hereunder will be in accordance with, and subject to, all applicable laws, including holdback requirements under Builders´ Lien Act (Nova Scotia).

9.0 Taxes and Duties:
Unless otherwise stated in this PO, the Seller will pay, and indemnify NSPI against all sales and commodities taxes, goods and services taxes, withholding taxes, customs duties, excise taxes, export and/or import tariffs and fees and any similar taxes, levies, assessments, tariffs or fees.

10.0 Indemnities:
The Seller shall at all times indemnify and save harmless NSPI all loss, costs, charges, damages, expenses (including legal fees), damages, claims and demands whatsoever that NSPI may incur by reason of:

(i) Personal injury, death, loss or damage to property arising out of, in the course of, or in any way connected with the performance of this PO but excluding any such injury, death, loss, or damage to the extent that same is caused by the negligence or willful act or omission of NSPI; or

(ii) any claim by a third party(s) that possession or use by NSPI of any intellectual property delivered as a part of or in connection with the Goods or Services infringes any patent, copyright, trade secret or other intellectual property right.

The Seller, at his own cost, risk, and expense, will defend any and all actions, suits, or other legal proceedings that may be brought against NSPI for any such claim or demand and satisfy any judgment that may be rendered against NSPI in any such action, suit, or other legal proceedings.

Except for the Seller´s obligations to indemnify NSPI neither NSPI nor the Seller shall be liable to the other for any consequential, special, incidental, multiple, exemplary or punitive damages for performance or non–performance under this PO.

11.0 Warranty:
Seller warrants that all Goods are of good, sufficient and merchantable quality, fit for the purpose or purposes specified and are free from any defect in design, material, workmanship or title. The Seller, at NSPI´s request, will either promptly replace or repair at the Seller's expense any defective or damaged Goods which, in NSPI's opinion, fail to comply with specifications or requirements under this PO or NSPI may, at its option and on reasonable notice to the Seller, correct such default, failure or damage and the Seller is liable to NSPI for all costs incurred in doing so. Neither payment for nor inspection, testing or acceptance of any Goods by NSPI excludes or limits any warranties hereunder or implied by law. The Seller will assign to NSPI, or enforce for NSPI's benefit, any warranties obtained from manufacturers or subcontractors. All warranties continue in full force and effect notwithstanding any termination of this PO. Unless set out otherwise herein, warranties with respect to the supply and/or installation of Goods will expire twelve (12) months from receipt by NSPI of such Goods. Should any Goods, or part thereof, be repaired, or replaced the warranty obligations of Seller under this PO shall extend to all such repairs or replacements.

The Seller warrants that all Services performed shall be performed in a professional and workmanlike manner using personnel with the skills and training appropriate for the assigned tasks and using equipment that is appropriate for the purpose for which it is supplied and functioning properly. Seller further warrants that it shall re–perform Services which are found to have been in breach of the foregoing warranties for a period of twelve (12) months following completion of the Service.

Except as otherwise provided herein, the foregoing warranties are exclusive and are in lieu of all other warranties and guarantees whether written, oral, implied or statutory. NO IMPLIED STATUTORY WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE SHALL APPLY.

12.0 Default:
NSPI may immediately terminate this PO if: (i) the Seller breaches a material term of this PO; or (ii) the Seller is insolvent, declared bankrupt, seeks the benefit of any insolvency legislation, or if a receiver is appointed in respect of the Seller or over a portion of the Seller´s assets. Upon such termination, NSPI is relieved of all further obligation hereunder. The Seller is liable to NSPI for all costs, expenses and/or damages (including legal fees) incurred by NSPI in completing or procuring the completion of this PO in excess of the purchase price.

13.0 Termination:
This PO may be terminated by NSPI, in whole or in part, by thirty (30) days prior written notice to the Seller for any reason subject to an equitable adjustment between the parties for work or materials supplied up to the date of termination. Such adjustment does not apply to Goods which are Seller's standard stock. The Seller is not entitled to any compensation or damages for any direct or indirect damage, loss, prospective profits, economic loss or incidental or consequential damages as a result of such termination. Immediately upon receipt of such termination notice, the Seller will discontinue all work under this PO and make every effort to cancel orders or contracts that have been made. Any claim for adjustment by the Seller must be asserted within thirty (30) days from the date of termination.

14.0 Insurance:
The Seller shall maintain the following insurance coverage for the duration of the PO: (i) Comprehensive General Liability insurance with limits of not less than $2,000,000 per occurrence for bodily injury or death, and $2,000,000 per occurrence property damage plus contractual liability coverage; (ii) automobile liability insurance: $2,000,000 per occurrence; and, if applicable, (iii) environmental impairment liability: $2,000,000 per occurrence. NSPI shall be named as an additional insured on the Seller´s insurance policy(s). Upon request, the Seller shall provide NSPI with certificates of insurance satisfactory to NSPI evidencing that the foregoing insurance has been obtained.

15.0 Dispute Resolution:
In the event of a dispute in connection with this PO, a senior officer of the Seller and a senior officer of NSPI shall meet to discuss and resolve the dispute and the parties shall have ten (10) days to resolve the dispute (or five (5) days if either party notifies the other party that the matter requires urgent resolution). In the event resolution cannot be achieved then such dispute or difference shall be referred to arbitration under the provisions of the Commercial Arbitration Act of Nova Scotia. Unless otherwise requested by NSPI, there shall be no stoppage in the provision of Goods or Services during any dispute resolution process.

16.0 Compliance with Laws:
The Seller shall comply with all statutory and legal requirements within the Province of Nova Scotia necessary for the performance of this PO by the Seller as well as all NSPI safety policies.

17.0 Force Majeure:
Neither the Seller nor NSPI shall be liable for any failure to comply with this Agreement to the extent that and for as long as such failure is caused by a Force Majeure Event. "Force Majeure Event" means any event or circumstance not reasonably within the control of, or not caused in whole or part by the negligence of, the party affected which wholly or partly prevents the performance by that party of its obligations under this PO, provided that such party is in good faith unable to perform such obligations by any commercially reasonable substitute means. Force Majeure Events include acts of God, war, riot, fire, explosion, flood, hurricane, acts of governmental authorities or acts of terrorism. Dates of delivery and/or performance may be extended by a period equal to the time actually lost by reason of a Force Majeure Event; provided, however that any deliveries and/or performance delayed or not made for reasons of Force Majeure Event may be suspended, reduced or cancelled by NSPI without any cost or obligation to NSPI. The party claiming a Force Majeure Event must give written notice to the other party within two (2) days of becoming aware of the Force Majeure Event and must also use commercially reasonably efforts to remedy the condition that prevents performance and to mitigate the effect of the same in order to continue to perform its obligations under hereunder.

18.0 Confidentiality:
The Seller and NSPI (as to information disclosed, the "Disclosing Party") may each provide the other party (as to information received, the "Receiving Party") with "Confidential Information." "Confidential Information" shall mean all the terms of this PO, all information about the Goods or Services and all information related to the business or products of the Disclosing Party that is not generally known to the public. The obligations of this Article shall not apply to any portion of the Confidential Information which: (i) is or becomes generally available to the public other than as a result of disclosure by the Receiving Party, or (ii) is or becomes available to the Receiving Party or on a non–confidential basis from a source other than the Disclosing Party, or (iii) has been or is subsequently independently developed by the Receiving Party without reference to the Confidential Information, or (iv) which the Receiving Party is required to disclose by law or a regulatory body with regulatory responsibility over the Receiving Party.

The Receiving Party agrees to: (i) use the Confidential Information only in connection with this transaction and permitted uses of the Goods and Services, (ii) not use, reveal, release, disclose or divulge the Confidential Information in any form whatsoever to any person or publish in any manner whatsoever, other than as permitted hereby, unless it has the prior written consent of the Disclosing Party; and (iii) to safeguard the Confidential Information from unauthorized disclosure.

19.0 General:

(a) This PO shall be construed in accordance with the laws in force in the Province of Nova Scotia, Canada and the federal laws of Canada applicable therein. The parties agree to attorn to the jurisdiction of the Courts of Nova Scotia.

(b) This PO shall enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns. The Seller will not assign or otherwise transfer this PO or any part hereof without NSPI's prior written consent, which may be unreasonably withheld by NSPI.

(c) Any failure by NSPI at any time or from time to time to enforce or require the strict keeping and performance of any of the terms or conditions of the PO shall not constitute a waiver of such terms or conditions. NSPI may at any time avail itself of such remedies as it may have for any breach of such terms or conditions.

(d) If any section or part or parts of sections in this PO are determined to be illegal or unenforceable, it or they shall be considered separate and severed from this PO and the remaining provisions of this PO shall remain in full force and effect and shall be binding upon the parties hereto as if such section or sections or part or parts of the sections had never been included.

(e) Section headings used herein are for the convenience only and shall not be construed so as to affect the interpretation or construction of this Agreement.

(f) In this PO, words importing the singular include the plural and vice versa and words importing a specific gender include all genders.

(g) The words "includes" or "including" shall mean "includes without limitation" or "including without limitation", respectively.

(h) In the event there is more than one Seller, all obligations of Seller hereunder are joint and several.

(i) All provisions of this PO which by their express terms or nature are continuing shall survive the expiration or termination of this PO, including this provision, and any provisions relating to notice, confidentiality, indemnification, termination, intellectual property, dispute resolution, as well as any provisions which are required to determine, or which exclude or limit, any liability or which are otherwise required to give effect to or interpret any such provisions which are continuing.

Environmental Statement

Nova Scotia Power is committed to conducting business activities in a manner which is respectful and protective of the environment, and strives for continual improvement of its environmental management systems. Contractors and suppliers are encouraged to help Nova Scotia Power identify opportunities to enhance environmental initiatives through use of appropriate products or services.

It is vital to Nova Scotia Power, our customers and our stakeholders, that contractors and suppliers understand our commitment to the environment and to adhere to company standards. Contractors and suppliers are required to comply with applicable environmental laws and regulations and to adhere to best management practices wherever appropriate.

Nova Scotia Power encourages, but does not require, that Contractors or Suppliers explore opportunities to develop ISO 14001 equivalency with their environmental management systems.

To learn more about our environmental management systems, please contact us via our website: www.nspower.ca