25 April 2012

Mr. Nelson Seymour, P. Eng.
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Dear Nelson,

NALCOR Holyrood Generating Station (Holyrood) Life Extension Review

As per our agreement, we have completed the high level Holyrood Life Extension Review. I trust that the report satisfies your needs.

Thank you for the opportunity to work on this small project. We look forward to helping you with a more detailed assessment in the future.

Yours truly,

Blair Seckington

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NALCOR Holyrood Generating Station Life Extension Review

April 25, 2012

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NALCOR Holyrood Generating Station Life Extension Review

1 Introduction

AMEC was contracted to provide a brief letter type assessment of the probability of cost for capital expenditures to extend the life of NALCOR's three unit oil fired Holyrood Thermal Generating Station (Holyrood) as a thermal generating station to the year 2035. The primary assumption provided is that the station would operate at a capacity factor of 75%.

The document would where practical note similar initiatives at other plants for cost bench marking, or reasonable costs per MW of plant capacity, with some consideration to if bench marked plants were coal fired and if they have had a history of operating at high capacity factors.

It was noted that if Holyrood were to continue as a thermal station, then it is expected that sulphur dioxide scrubbers (flue gas desulphurization – FGD) and particulate collection devices (electrostatic precipitators – ESP's) would be installed within the next 5 years. The report was not required to allow for the capital cost of installing this large environmental addition to the plant, as NALCOR have that information on file from a 2009 study by STANTEC. The report should consider probable capital costs thereafter to enable its continued operation to the year 2035.

2 Assumptions - Holyrood Life Extension

The report addresses only the Holyrood station and does not address any additional scope outside of Holyrood. The assumptions used for staffing in the analysis are:

- Reliable Operation of all three units to 2035
- A plant annual capacity factor of approximately 75%, spread between the three units
- No unit two shifting or deep cycling (i.e. normal minimum load of 70 MW; normal operating level about 80% to 90% of full load
- Plant staffing and maintenance contracting is consistent with current levels
- Sulphur dioxide scrubbers (flue gas desulphurization – FGD) and particulate collection devices (electrostatic precipitators – ESP's) would be installed by 2018 and maintained thereafter
- No synchronous condenser conversions of Units 1 and 2
- High operating reliability and availability are required, consistent with recent historical levels

3 Benchmarking

Benchmarking life extension requirements and costs is difficult. There are many differences to take into account, including:

- Unit/equipment: vendor, redundancy, unit size and system criticality, quality, margins,
- Fuel type: coal, high sulphur/vanadium oil, low sulphur/vanadium oil, natural gas
- Operating mode: baseload, seasonal base load, intermediate load, peaking
- Operating history: operating hours, starts/stops, cycling/two-shifting
- Maintenance history: extensive, predictive, preventative, reactive, unit scavenging
- Interconnection and alternative generation options

- Life extension period: 10 years, 30 years
- Life extension role: insurance, base load, peaking
- Life extension methodology: up front refurbishment, extended planned program, ad-hoc as required, combinations

Most utilities in North America have typically operated their larger, critical fossil units as base-loaded facilities with minimal cycling or starts and stops. These units are very well maintained and funded. Essentially life extension for these units means that they continue to be maintained and refurbished on an on-going basis with major investments on a time based plan versus a one-off re-investment or reactive basis.

Smaller, older units in North America utilities are usually used for peaking, but often do not "two shift" (i.e. turn on and off once or twice per day to meet electricity demand daily peaks). They typically receive the minimum practical maintenance and refurbishment funding and essentially often limp along because they are a low cost producer. The utilities and their customers rely on their interconnections to provide them the flexibility and reliability necessary to do this. If and when a major investment (i.e. generator replacement, environmental controls retrofit) is required, the utility will seriously consider closing the units as a viable alternative.

The fossil fleet of Ontario Hydro/Ontario Power Generation (OPG) has been a significant exception to the North American norm. The role played by OPG fossil units has varied almost yearly. The fossil generation levels have varied over the years from as high as 45 TWh/year to as low as 3 TWh/year. Many units have been required to two-shift and have experienced 200 starts and stops per year, with as many as two starts per day for meeting daily peaks. In low generation years and when generation has been predicted to stay low for extended periods, maintenance and capital re-investment has been minimized. In some stations, some units have been cannibalized/scavenged to maintain others. At the same time, the two shifting increased and has wreaked havoc on the equipment resulting in very high EFOR (Effective Forced Outage Rate). OPG is one of the few utilities that implemented a one-off re-investment as well as a reactive basis approach to large 300 to 500 MW fossil units.

i. Lakeview Generating Station – eight 300 MW bituminous coal fuelled units having a combination of various steam turbine generator vendors/types and boiler vendor/types with in-service in the early to mid 1960's. Located in Mississauga (just west of Toronto), the station provided peaking service from about 1980. In the early to mid-1990's when load appeared to be on the verge of significant growth, it was clear that after 35 years Lakeview units were in dire need of refurbishment. It was decided to extend the life of all eight units by 10 years from 1996 to 2006 at a cost of about $1 billion or about $400/kW. The project was initiated but cost overruns and lower load forecasts resulted in the scope being reduced to four units and the common areas. The final all-in cost remained at about $1.0 billion or about $800/kW. After the refurbishment was completed, load had dropped and the plant experienced very low loading, extensive two shifting, minimal maintenance and unit scavenging (resulting in higher EFOR than had been planned). The plant limped along until the early to mid 2000's (about its planned life extension date) before it was decommissioned and demolished.

ii. Nanticoke Generating Station – an eight 500 MW coal fired station located on the north shore of Lake Erie. The plant was installed in stages with in-service dates between 1972 and 1976. The Nanticoke station is a critical part of the Ontario system as far as both capacity and system stability is concerned. It has operated at annual capacity factors from as high as 65% to as low as 10%. Units in the station vary from a seasonal base load operation to a 200 to 300 start per year daily peaking unit. In the early 1990's the station went through an extended low generation period at about a 17% annual capacity factor and 200 to 300 starts/stops/unit/year. Maintenance was reduced. Some inter-unit scavenging was used. The EFOR (and unit unavailability) rose from moderate levels to levels as high as 12 to 20%. Equipment issues early in the plant life and in mid-life included various boiler issues and major problems with generator failures. As load picked up in the later 1990's, the requirement for Nanticoke units to be reliable sources grew and a minor refurbishment was undertaken. About $200 million was spent on unit specific reliability related items and primarily on four of the units (effectively $100/kW). In addition significant dollars were spent on environmental improvements and on lower cost (but cleaner) fuel upgrades to fuel handling and boiler areas. Subsequently an additional capital program of about $50 million per year was implemented for life sustaining purposes. Over the period to 2002/3, this effectively contributed another $50 to $100/kW. There were also major investments in environmental clean-up ($125/kW on 2 units for NOx back-end control), for further fuel flexibility, for particulate clean-up, for fuel handling, for gas ignition, and other items. In 2003 with the initiation of the "close coal" process by the provincial government and recently the very low cost of natural gas used in combined cycles installed in the 2002-2012 period, Nanticoke operation has been reduced to four units on peak capacity service only (very low capacity factors, two-shifting as required). Maintenance is at minimal levels and non-operational scavenging likely used to reduce costs.

iii. Lambton Generating Station – a four unit 500 MW/unit bituminous coal fired station located on the St. Clair River south of Sarnia. The plant was installed in stages with in-service dates between 1970 and 1972. Units 3 and 4 at the Lambton station were equipped in 1986 with flue gas desulphurization (FGD/Sulphur dioxide scrubbers) and subsequently ran as base load units through the period until the early 2000's. Units 1 and 2 were converted to fire on more expensive, low sulphur bituminous coal in the 1980's and operated primarily as peaking/two shifting units. They were briefly mothballed in the 1990's during the low load period, but returned to service later in the 1990's as load picked up. They were mothballed again about 2010 as part of the provincial "close coal initiative". All Lambton units have the same boilers (CE) and the same (GE) steam turbine generators and these have performed very well. As part of the FGD retrofit, OPG also undertook some refurbishment of primarily Units 3 and 4. The refurbishment component was between $300/kW and $450/kW for those two units. The units are considered well able to operate to 2020+ (about 50 years), although the close coal initiative would see Units 3 and 4 close by the end of 2014. The FGD and associated modifcations (limestone handling, gypsum handling, waste water treatment, fans, ducting, stack) was about $450/kW. The major refurbishments for the FGD have included lining repairs, booster fan repairs, stack liner failure replacement, gypsum handling system improvements. Originally an annual 2% of direct capital maintenance allowance was assumed with about half being longer term refurbishment issues. This amounted to about $50/kW in about year 10 to 15 after FGD in-service.

Although benchmarking may provide some insights, each plant is unique, based on factors as mentioned previously including the grid that it is associated with. Holyrood is very unique because it operates in an island mode and it is the only major steam cycle thermal station on the grid.

3.1 Other Benchmarks

No specific large scale re-furbishment for specific life extension was noted from previous involvement with staff from many US utilities (i.e. Southern Company, AEP, Duke). Most had a planned maintenance program that addressed a longer than 40 year life for their major base load facilities/units. Typically their major incremental investment concerns dealt with large emission control expenditures for sulphur dioxide (FGD), nitrogen oxides (NOx – selective catalytic reduction (SCR)), and mercury (activated carbon injection). While most larger coal stations have been or will be retrofitted to comply with regulations, many smaller stations will be closed or converted to gas fuelled peakers if required. Closures may depend on how carbon dioxide (CO_2) reduction credits can be managed. As a result, most smaller coal plants/units are managing with minimal resources and investment. The utilities manage this through interconnections.

Oil fuelled units/facilities in North America are typically peaking facilities. Many have been closed or converted to natural gas. Many have been replaced by simple cycle gas turbines. The exceptions tend to be local facilities serving a specific need and for which alternatives are not available or not yet implemented. OPG's four 500 MW unit Lennox Generating Station is an exception. Lennox was installed as an oil fired facility in the early 1970's, but was converted to dual natural gas and low sulphur #6 oil firing capability in the 1990's. The fuel used depends on fuel price differentials. Two or all four units have been mothballed for brief periods in its history. It is currently essentially a peak capacity insurance policy, with a system contract for capacity capability to support its fixed costs. It installed some quicker start capability in the 1990's and early 2000's that has made it attractive for this role. It has had minimal capital investment, with the exception of the addition of dual fuel firing. Given the quality of the equipment and the minimal operation it is expected to be capable of operation in its current role at least to 2020. Actual operation will depend on the system need for the insurance capacity.

4 Holyrood Life Extension Assessment Considerations

Several factors about Holyrood, its previous and forecast operation, and its previous and forecast maintenance will have a significant effect on the life extension cost and approach. These include:

i. Holyrood physical age/life– Holyrood over its life has operated as a seasonal base load station. The age of the units are:

a. Unit 3 since start up in 1979 – 33 years now, 56 years in 2035; ;
b. Unit 2 since start up in 1970 – 42 years, 65 years in 2035; and
c. Unit 1 since start up in 1969 – 43 years, 66 years in 2035.

From an age perspective, Units 1 and 2 are now slightly beyond the typical 40 year technical life of a unit of their type. Unit 3 will be 40 years old in 2019, well within the period if the station life was extended to 2035. There are however many smaller coal units in the United States and elsewhere still operating up to 60 years.

ii. Holyrood operating hours – Holyrood over its life has operated as a seasonal base load station. The operating hours on the units are:
   a. Unit 3 since start up in 1979 – about 130,000 operating hours (plus 40,000 hours for generator and electrical systems in synchronous condensing operating), 280,000 (plus 40,000 synchronous condensing hours on generator and electrical systems) in 2035;
   b. Unit 2 since start up in 1970 – about 175,000 operating hours, 325,000 in 2035; and
   c. Unit 1 since start up in 1969 – about 165,000 operating hours, 315,000 in 2035.

From an operating hours perspective, Units 1 and 2 are currently well within their reasonable design life for most major components that are related primarily to operating hours. Units 3 is more so, although the generator and electrical systems are similar to Units 1 and 2 due to the additional synchronous condensing operation. By 2035, all three units will be beyond the typical 200,000-250,000 operating hours associated with a base load 30 year life without major equipment refurbishment.

iii. Holyrood operating mode – Holyrood over its life has operated as a seasonal base load station. The starts/stops on the units are very low per year, between 2 and 20. Over their life:
   a. Unit 3 since start up in 1979 – about 340 start/stops, 560 likely by 2035
   b. Unit 2 since start up in 1970 – about 480 start/stops, 700 likely by 2035; and
   c. Unit 1 since start up in 1969 – 480 start/stops, 700 likely by 2035.

A key factor for Holyrood is that most of its operating hours have been between 50% and 80% of full load, with no significant load following cycling and very few starts/stops per year and no two shifting. This duty reduces the impact of operating hours on some of the major equipment and effectively extends the expected life of those units/equipment.

iv. Holyrood Fuel – Over much of its life, Holyrood had been fuelled with a higher sulphur (2.5%S+), higher vanadium heavy fuel oil. It switched to a lower sulphur (0.7%S), lower vanadium fuel in 2009.

The original fuel resulted in extensive corrosion of parts of the boiler and the air preheater and ductwork. Additives and extensive outages for cleaning several times a year were necessary to minimize downtime and to operate the unit. As a result there were several parts of the boilers that were repaired or replaced earlier than might have been normal otherwise. The adoption of the higher quality fuel has had a drastic effect (reduction) on outages, corrosion, refurbishment requirements.

5 Assessment of Holyrood's Life Extension Requirements

5.1 High Level Refurbishment Cost

A typical near end of life once-off refurbishment for this type of facility, given current unit costs, would be about $400/kW. For Holyrood, this would equate to about $200 million, excluding the capital costs for adding FGD and ESP's likely required in or about 2018. It is likely that a further additional refurbishment cost for the plant and for the FGD would be required in or about 2023 to 2027 of about $80/kW or about $40 million. Some initial FGD start-up issue resolution costs and annual $2 million per year capital expenditures are also likely.

5.2 Holyrood Life Extension Approach

Holyrood units are considered to be in good condition for their age. They have generally been well maintained and seen moderate re-investment to resolve previous issues (primarily related to the boiler and its air-pre-heater and combustion system). Their seasonal base load operation, including no two shifting, minimal heavy cycling, moderate lower load limit, and modest full load operating time, has not imposed any severe conditions on the major equipment that would impact its life or refurbishment needs.

A major one-off refurbishment is not considered to be the best approach or required to enable Holyrood to continue the planned annual base load operation to 2035. Economically, such an approach is generally higher cost in present value terms and provides minimum flexibility going forward. A more appropriate refurbishment that would allow the plant to continue to provide reliable service and capacity would be staged between 2013 and 2017. Initial planning and engineering work would commence in 2013 and the refurbishment of key elements between 2014 and 2017. Some incremental refurbishments would be undertaken each year as required and a further minor refurbishment program is likely required in 2024/26. The FGD would require some start-up modification capital in 2018/19, a modest refurbishment about 2025 with an annual capital allowance.

Key issues going forward would be the generators and auxiliaries (rotors and stators and auxiliary hydrogen and lube oil equipment), select steam turbine elements (efficiency improvements not included, but at 70%+ annual capacity factor should be considered and assessed in 2013), electrical and DCS upgrades, boiler surface replacements and auxiliaries (condition dependent, some previously replaced so assumed moderate), remaining fuel storage and handling upgrades, marine terminal environmental upgrade, and some plant transformer refurbishments/replacements. It does not include any main transformer replacements/major refurbishments that are not part of Holyrood assets (likely about $10 million in 2020 to 2025 period).

6 Recommended Life Extension Costs

Given the time available and scope of this analysis, no detailed analysis was performed. Some consideration was given to some previous draft work on a 20 year capital plan for synchronous generation and how that might be modified to reflect a generation scheme. This was considered in light of the higher level industry experience (primarily OPG coal units).

The following high level refurbishment cashflow is recommended as a reasonable starting point for initial consideration, subject to significant further detailed assessment.

Base Capital Costs Millions 2012$/ Year	5.0	40.0	45.0	50.0	40.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	15.0	10.0	10.0	10.0	5.0	3.0	3.0	0.0	180.0	119.0	299.0
FGD/ESP Capital Costs Millions 2012$/ Year						4.0	4.0	2.0	2.0	2.0	2.0	2.0	25.0	2.0	2.0	2.0	2.0	2.0	1.0		0.0	54.0	54.0
Total Capital Costs Millions 2012$/ Year	5.0	40.0	45.0	50.0	40.0	13.0	13.0	11.0	11.0	11.0	11.0	11.0	40.0	12.0	12.0	12.0	7.0	5.0	4.0	0.0	180.0	173.0	353.0
Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2013-2017 Projects	2018-2032 Projects	Total 2012-2032