2008 Long Term Acquisition Plan

APPENDIX F7

AMEC Natural Gas-Fired Combustion Turbine Power Plant Costs and Performance Update Report

BC hydro

BC Hydro
Vancouver, British Columbia

BC Hydro 2008 Resource Options Update
Gas-fired Combustion Turbine Power Plant Costs and Performance Updates

AMEC 157 842

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DISCLAIMER

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1 INTRODUCTION

AMEC Americas Limited (AMEC) was requested to prepare a pre-feasibility-grade capital and operating cost estimates of a nominal 100MW simple cycle power generating plant for peaking duty. The estimates were to be on the basis of costs in October 2007.

In addition, AMEC was instructed to update the capital and operating costs for the units that were included in the AMEC Report of 8 December 2006, and bring them to an October 2007 cost basis, by applying appropriate escalation. The plants of the BC Hydro 2005 Resource Options report comprise:

- Simple cycle 47MW gas turbine power plant
- Combined cycle 60MW gas turbine power plant
- Combined cycle 250MW gas turbine power plant, and
- Combined cycle 500MW gas turbine power plant.

It is noted that the 2005 ROR net generating capacities for the simple cycle gas turbine (SCGT) power plant of 47MW and the combined cycle gas turbine (CCGT) power plant of 60 MW in this report are revised to 40 and 50 MW respectively for reasons that are detailed in the appropriate sections that follow.

Following award of the work to AMEC, it was determined in discussions with vendors that significant changes in gas turbine package prices had occurred in the last year, so BC Hydro requested updated turbine equipment package prices to be included in the updates.

The location of all plants is to be in the Kelly Lake/Nicola region, which is at an elevation of approximately 600m.

With the exception of the 100MW simple cycle plant, the technical and cost basis of all of these plants has been reviewed and updated for BC Hydro in three earlier AMEC reports:

- *Thermal Power Plant Performance Review, Emissions and Costs Review* dated December 2003 (AMEC Project 142 194)
- 2004 Integrated Electricity Plan General Thermal Review, dated March 2004 (AMEC Project 142 194)
- Comments on Gas Turbine Power Plants Costs and Performance in Appendix F of the 2005 Resource Options Report (2005 ROR), dated 6 December 2006 (AMEC Project 154 361).

2 BASIS OF COST ESTIMATES AND ESCALATION RATES

2.1 Capital Costs

The estimates of capital cost are based on vendor budget pricing of the turbine equipment package with the balance of plant direct costs and other indirect costs and contingencies estimated on a factored basis. Estimated factors for the balance of plant for the 40MW (formerly 47MW) and 100MW units were developed from an analysis of AMEC in-house data from past projects and studies.

For the 50MW (formerly 60MW), 250MW and 500MW units, the factors were developed from breakdowns of cost categories in a study completed by Bantrel[1] in 2001 made available to AMEC by BC Hydro. The Bantrel estimates are priced in 4Q 2000 Canadian dollars. It is noted that the Bantrel study is of feasibility accuracy and uses a contingency of 20%. The report states that with this contingency included, there is a 70% probability of under-running the estimated project cost. With this level of detail, the costs provide a good basis for pre-feasibility estimates.

Direct costs as defined in the 2005 Resource Options Report "...include interconnection costs and all project development costs." The line item cost allowances for interconnection costs and environmental permitting for the Bantrel cases were discussed with BC Hydro. From these discussions, preliminary allowances were made to provide for these costs for the 40MW and 100MW SCGT cases. Also adjustments were made to the Bantrel allowances for water and sewage and greater allowances were provided for environmental permitting for the CCGT cases. This process established nominal allowances. The allowances escalated to 3Q 2007 basis and added to the capital cost estimates are shown in Table 1.

[1] Bantrel Inc., *Greenfield Combined Cycle Gas Turbine Feasibility Study, Phase II, Technology Assessment*, 2001

Table 1 - Allowances in Direct Costs Estimates, millions $ (basis: 3Q 2007)

	40MW	50MW	100MW	250MW	500MW
Gas pipeline spur and metering	1.3	1.5	1.5	2.8	3.5
Water and sewage	0.2	1.0	0.2	1.6	2.0
Electrical transmission interconnection	1.5	1.8	2.0	3.3	4.0
EIA and permitting	1.0	1.3	1.3	1.5	1.6
TOTALS	4.0	5.6	5.0	9	11

The use of factors for estimating is less accurate when prices of different cost groups vary by different amounts, whether due to shifts in foreign exchange rates or in the price of major equipment packages, or construction costs. Both the capital cost estimates, and to a lesser degree operating and maintenance cost estimates presented in this and earlier AMEC studies are affected by these shifts. To improve the reliability of these pre-feasibility estimates it was considered important to use the older more detailed Bantrel study for the basis of factors, where estimates based on the then current costs would be more reliable, given that the previous decade was a period of relatively more stable equipment prices and US dollar exchange rates than in the last 12 months.

It is noted that this approach differs from that adopted in AMEC's December 2006 report (*Comments on Gas Turbine Power Plants Costs and Performance in Appendix F of the 2005 Resource Options Report,* AMEC Project 154 361) which was based on escalating the 2004 costs of the 2005 ROR estimates to bring them to an October 2006 basis. The mandate did not include investigation of the basis of the ROR estimates themselves. A decision for this change of approach was made mid-way through this study, when it was clear that the 2005 ROR capital costs seemed high and background information supporting them was lacking.

It will be noted that the capital cost estimates in this study differ slightly from earlier estimates, but we believe these estimates are more readily justified than the former approach. In summary, the reasons for the difference are:

- In 2006, breakdown of capital costs was based on AMEC in-house factors and the 2005 ROR

- For the combined cycle cases, the current study escalates the year 2000 estimates from the Bantrel Feasibility Study data which provides a documented basis of estimate.

Budget prices for the gas turbine generator and the steam turbine generator packages used in estimates were obtained from General Electric (GE). These were quoted in US dollars and since the US-Canadian exchange rate was fluctuating around unity, parity was assumed for this study for the third quarter 2007,

2.2 Inflation of Capital Costs

For purposes of estimating the inflation of capital cost, the estimates were broken down into the following groups:

- Gas and Steam Turbine Generator Packages
- Other Equipment
- Canadian Construction Costs Including Indirects

Current prices for gas and steam turbine generator packages were based on vendor quotes received in September 2007.

'Other Equipment' is inflated using the Chemical Engineering Index for Process Machinery. The index was used as a proxy for general machinery price increases internationally and accordingly is not adjusted to Canadian dollars, on the basis that much of the equipment could be considered sourced in Europe or the Far East. This results in a fairly significant increase in prices that AMEC considers justified, given the recent shifts in US exchange rates, and inflation of costs of projects internationally. As the data is only available to May 2007, year-to-year index was based on the month of May data.

'Canadian Construction Costs Including Indirects' comprise the construction costs of the plant and indirect costs associated with the project. Construction costs cover site preparation, field construction, and installation of the equipment and structures of the plant. Indirect costs include construction management, contractor's overhead, owner's costs, engineering and contingency, but not interest during construction. For purposes of estimating the inflation of construction costs, an analysis of estimates showed that *Canadian Construction Costs Including Indirects* consisted of, averaged across projects, an estimated 25% labour with the balance reflecting field construction costs. Accordingly, the inflation of '*Canadian Construction Costs Including Indirects'* was estimated using the 25/75 percent ratios in conjunction with:

- An index based on the BC Building Trades labour agreement for UA Local 170 which is effective currently through April 30, 2010 adjusted for an erosion of labour productivity assumed to be 5% per year starting in 2004 and totaling 20% by 2007.
- Non-residential Building Construction Cost, Quarterly non-residential building construction price index, Seven City Composite, from Statistics Canada Table 327-0039 referenced in B C Hydro-Engineering: Recommended Inflation Rates, 31 March 2007.

The costs inflation factors are presented in Table 2.

Table 2 - Cost Inflation (year 2000=100)

	2000-10	2001-10	2002-10	2003-10	2004-10	2005-10	2006-10	2007-10
Cdn construction costs incl. indirects (a)	100.0	105.3	106.4	109.7	113.5	123.3	130.7	142.8
BC Labour Rate + Productivity Adj. Index (b)	100.0	100.1	100.3	105.7	111.1	120.7	131.5	143.4
Construction Cost Index (c)	104.8	112.2	113.6	116.4	119.8	130.1	136.7	149.4
Construction Cost Index, year 2000=100	100.0	107.1	108.4	111.1	114.3	124.1	130.4	142.6
Chem. Eng. Process Machinery Index, US$	438.9	441.8	439.0	449.5	487.6	519.7	543.1	603.6
Other equipment (d)	100.0	100.7	100.0	102.4	111.1	118.4	123.7	137.5

NOTES:

a - Cost inflation of "Cdn construction costs incl. indirects" is 75% Non-residential Building Construction Cost Index + 25% BC Labour rate index (next rows), year 2000 = 100

c - Non-residential Building Construction Cost Index (BC Hydro-Engineering: Recommended Inflation Rates, 31 March 2007).

d - "Other equipment" escalation is based on the Chemical Engineers Indices for Process Machinery, but not converted to Canadian Dollars, year 2000 = 100

2.3 Inflation of Operating Costs

The inflation of '*Fixed Operating and Maintenance Costs*' was estimated using the index BC Building Trades labour cost (adjusted for productivity) just described.

The inflation of '*Variable Operating Costs*' were estimated using the Chemical Engineering Index for Process Machinery, converted into Canadian dollars, as these are for the most part charges by the major equipment package vendor, GE. These charges are related directly to operating hours logged and therefore considered as variable costs.

3 SIMPLE CYCLE GAS TURBINE – 40 MW

3.1 Capacity

The Section Title and 2005 ROR heading uses 47MW as the case was apparently based on the Sprint version of the General Electric LM 6000 which uses water injection and had Selective Catalytic Reduction (SCR) for

NOx control. The more recently developed dry low NOx LM 6000 PD version is selected for this estimate as using water and steam systems would be a disadvantage for the remote mostly unattended operation assumed here. This unit will meet a NOx limit of 25 parts per million dry volume (ppm_{DV}), NOx as NO_2. It is assumed there is no need to reduce NOx levels further by adding SCR as this plant is designed for peaking service only.

The 2005 ROR heading accordingly should be revised to 40MW, to reflect the nominal output if located in the Kelly Lake/Nicola region.

The General Electric LM 6000 PD gas turbine with dry low NOx control has an ISO power output of 41.7MW. The ISO performance rating is at sea level with an air temperature of 15°C.

The As New output at this location of altitude 600m and 15°C is 39.0MW. Allowing for an average 2% degradation in capacity over the life of the plant, output becomes 38.2MW.

3.2 Heat Rate

It is suggested that the Heat Rate be clearly indicated in terms of the HHV of the fuel, as this way it is less likely to lead to errors in estimating fuel consumption. This is because gas fuel in North America, whether expressed in Btu or GJ is based on the higher heating value (HHV). This clarification is important, as it is industry practice worldwide to specify gas turbine performance in terms of the LHV value of the fuel.

The full load heat rate at this location is 9794GJ/GWh on an HHV basis (8840 GJ/GWh LHV) respectively taking into account an average degradation of 1% over the life of the plant.

3.3 Environmental

Emissions in tonnes per GWh at full load are estimated using the GE emission rates and for PM and SO_2 using the US EPA AP42 document. Estimates are based on the average degraded capacity and are estimated as follows:

		SOx	NOx	CO	VOC	PM10	PM2.5	CO2
Emission rate	kg/h	0.0005	15	9.01	3.1	1.2	0	19,450
" "	t/GWh	0.0000	0.39	0.24	0.08	0.031	Unknown	509

As an emission factor for PM10 was not available from AP42, PM_{10} is taken as equal to total PM and is therefore conservative. PM is the sum of the filterable and the condensable fraction.

3.4 Capital Cost

The pre-feasibility total installed capital cost including indirect costs is estimated at 43 million Canadian dollars. Included in this total is supply price of the gas turbine generator package of 18 million US dollars or 18 million Canadian dollars as exchange rate parity has been assumed for the third quarter 2007.

3.5 Fixed and Non-fuel Variable O&M Cost

The Fixed Operating and Maintenance (Fixed O & M) cost shown in 2005 ROR of $1 534 000 is very high in part because the amount includes a fixed gas toll, a fee based on the daily nominated consumption in GJ, which applies whether the gas is used or not. The unit also included selective catalytic reduction for NOx control which has high costs associated with it. Using technical literature and in-house data, the Fixed O&M costs for the power plant alone are estimated at $500,000/a in October 2007. This includes an amount of 15% for contingencies. This assumes remote dispatching and mostly unattended operation, though with an allowance for day shift operators.

The non-fuel variable costs assuming start-up in October 2007 are estimated at $4.0/MWh, compared with $3.9/MWh in the 2005 ROR. This includes an amount of 15% for contingencies. For clarity, the title should include the words: "Non-Fuel" In Fixed and Variable O & M Costs.

4 SIMPLE CYCLE GAS TURBINE – 100 MW

4.1 Capacity

This section describes a 100MW simple cycle plant which is being considered as a potential new peaking power supply resource.

Siemens provided a price for their 120MW unit which has dry low NOx control. At site conditions of 600m and 15°C, power output is 110MW. This is a heavy industrial type gas turbine which is capable of reaching full power output in 30 minutes from a cold condition. However, Siemens did not provide suitable operating cost data for the unit. Accordingly, the GE machine was selected.

The GE machine is an aero-derivative machine which would reach full output in a matter of minutes, but would require water injection for control of NOx to $25ppm_{DV}$. This requires well water supply, water demineralization and pumps at the site. GE is currently developing a version of this unit with the aim of providing dry low NOx control to $25ppm_{DV}$. It is expected to be available by late 2009.

There is no Selective Catalytic Reduction (SCR) included for this plant as it is designed for peaking service only.

The full load As New output for the GE machine at 600m altitude and 15°C is 99.8MW. Allowing for an average degradation in capacity of 2% over the life of the plant, this becomes 97.8MW dependable output.

4.2 Heat Rate

The full load heat rate at this location is 9208GJ/GWh on an HHV basis (8310 GJ/GWh LHV) respectively taking into account an average degradation of 1% over the life of the plant.

4.3 Environmental

Emissions in tonnes per GWh at full load are estimated using the GE emission rates and for PM and SO_2 from US EPA AP42 and are based on the average degraded capacity. Air emissions are estimated as follows:

		SOx	NOx	CO	VOC	PM10	PM2.5	CO2
Emission rate	kg/h	0.00004	36	134.6	3.7	2.8	0	46,694
" "	t/GWh	0.0000	0.37	1.4	0.04	0.03	Unknown	477

As an emission factor for PM10 was not available from AP42, PM_{10} is taken as equal to total PM and is therefore conservative. PM is the sum of the filterable and the condensable fraction.

4.4 Capital Cost

The pre-feasibility total installed capital cost including indirect costs is estimated at 70 million Canadian dollars. Included in this total is supply price of the gas turbine generator package of 35 million US dollars, or 35 million Canadian dollars as exchange rate parity has been assumed for the third quarter 2007.

4.5 Fixed and Non-fuel Variable O&M Cost

The Fixed Operating and Maintenance (Fixed O & M) cost was scaled from the 40MW power plant and on a pre-feasibility basis is estimated at $ 700,000/a in October 2007. This assumes remote dispatching and mostly unattended operation, though with an allowance for day shift operators.

The non-fuel variable pre-feasibility costs are estimated assuming start-up in October 2007 of $4.2/MWh.

5 GREENFIELD COMBINED CYCLE GAS TURBINE – 50 MW

5.1 Capacity and Heat Rate

The Section Title and 2005 ROR heading uses the 60MW output of the plant. The gross power however at 600m altitude and 15°C for the Kelly Lake/Nicola location of the General Electric LM 6000 PD dry low NOx technology unit is an estimated 51.5MW in a new and clean condition from the gas turbine and the steam turbine generators combined. Allowing 2% average degradation over plant life, output is estimated at 48.9MW. The 2005 ROR may be based on the Bantrel year 2000 report, which is at a site at much lower elevation.

Estimated heat rate increased by 1% is estimated at 7580kJ/kg.

5.2 Environmental

Emissions in tonnes per GWh at full load were re-estimated using the GE emission rates and for PM and SO_2 using the US EPA AP42 document. Estimates are based on the average degraded capacity and are estimated as follows:

		SOx	NOx	CO	VOC	PM10	PM2.5	CO2
Emission rate	kg/h	0.0005	2.1	9.01	3.1	1.2	0	19,450
" "	t/GWh	0.0000	0.04	0.18	0.06	0.024	Unknown	400

As an emission factor for PM10 was not available from AP42, PM_{10} is taken as equal to total PM and is therefore conservative. PM is the sum of the filterable and the condensable fraction.

5.3 Capital Cost

The pre-feasibility total installed capital cost including indirect costs is estimated at 139 million Canadian dollars. Included in this total is supply price of the gas turbine generator package of 18 million US dollars, or 18 million Canadian dollars as exchange rate parity has been assumed for the third quarter 2007.

The estimate includes a selective catalytic reduction system which had been included in the 2005 ROR. This will achieve a NOx emission of approximately 3.5 ppm_{DV}.

5.4 Fixed and Non-fuel Variable O&M Cost

The annual Fixed O&M Costs shown in 2005 ROR of $4.3 million are high in part because the amounts include a fixed gas toll. The Bantrel study gives estimated fixed operating costs which when escalated to 2004 amount to $2 500 000/a. Projected forward, Fixed O & M cost in October 2007 is estimated at $3 200 000/a.

The non-fuel Variable O&M Cost is estimated at $6.5/MWh in 2004 and is estimated to decline slightly to $6.4/MWh by October 2007 due to the increased value of the Canadian dollar during the period.

6 GREENFIELD COMBINED CYCLE GAS TURBINE – 250 MW

6.1 Capacity and Heat Rate

The net capacity and heat rate in the 2005 ROR of the General Electric FA gas turbine and steam turbine in the 107FA combined cycle package of the ROR Case Sheets indicate plant performance was based on a Kelly Lake/Nicola region location, but excludes degradation. Estimated heat rate is increased by 1.5% to 7350kJ/kg and capacity decreased by 3% to 236MW to reflect average degradation over plant life.

6.2 Environmental

No changes were made in the 2005 ROR emission data, except for rounding to one significant figure, though the greenhouse gas emission factor was increased to 365 CO_2/GWh.

6.3 Capital Cost

The pre-feasibility total installed capital cost including indirect costs is estimated at 317 million Canadian dollars. Included in this total is supply price of the gas and steam turbine generator packages of 65 million US dollars, or 65 million Canadian dollars as exchange rate parity has been assumed for the third quarter 2007.

The estimate includes a selective catalytic reduction system which had been included in the 2005 ROR. This will achieve a NOx emission of approximately 3.5 ppm_{DV}.

6.4 Fixed and Non-fuel Variable O&M Cost

The annual Fixed O&M Costs shown in 2005 ROR of 11 million dollars is in part very high because the amounts include the gas toll. Other data in the public domain ranged from 1.1 - 6 million dollars. Vendor provided third party data suggested a US$4.5/a/kW capacity assumed to be year 2000 basis, or about Cdn$1 800 000/a in 2004. This is more in line with data from the Bantrel study which gives estimated costs escalated to 2004 of $2 500 000/a. Projected forward, Fixed O & M cost at time of start-up in October 2007 is estimated at $3 200 000/a.

The non-fuel Variable O&M Cost is estimated at $4.6/MWh in 2004, the same as the 2005 ROR value. Variable O & M is estimated to remain essentially unchanged at $4.6/MWh through October 2007 due to the increased value of the Canadian dollar during the period.

7 GREENFIELD COMBINED CYCLE GAS TURBINE – 500 MW

7.1 Capacity, Heat Rate, and Potential for Technology Change

The net capacity and heat rate in the 2005 ROR of the General Electric FA gas turbine and steam turbine in the 207FA combined cycle package of the ROR Case Sheets indicate plant performance was based on a Kelly Lake/Nicola region location, but excludes degradation. Estimated heat rate is increased by 1.5% to 7362kJ/kg and capacity decreased by 3% to 479MW to reflect average degradation over plant life.

7.2 Environmental

No changes were made in the 2005 ROR emission data, except for rounding to one significant figure.

7.3 Capital Cost

The pre-feasibility total installed capital cost including indirect costs is estimated at 544 million Canadian dollars. Included in this total is supply price of the gas and steam turbine generator packages of 116 million US dollars, or 116 million Canadian dollars as exchange rate parity has been assumed for the third quarter 2007.

The estimate includes a selective catalytic reduction system which had been included in the 2005 ROR. This will achieve a NOx emission of approximately 3.5 ppm_{DV}.

7.4 Fixed and Non-fuel Variable O&M Cost

The Fixed O&M Costs shown in 2005 ROR of nearly 16 million dollars/a is in part very high because the amounts include the gas toll, a fee based on the daily nominated GJ, which applies whether the gas is used or not. The California Independent Systems Operators forecast US$15/kW capacity or about 7.5 million US dollars/a. Other data in the public domain ranged from 2.2 - 13 million dollars/a.

The cost data from the Bantrel study gives estimated costs for 2004 of $2 400 000/a. As this cost is largely operating labour and other fixed costs, it should not differ significantly from the 250MW plant as the machinery arrangements are similar with the exception that this larger plant has two gas turbine generators. Projected forward, Fixed O & M costs in October 2007 is estimated at $3 400 000/a.

The non-fuel Variable O&M Cost is estimated at $4.4/MWh in 2004 compared with $4.6/MWh of the 2005 ROR. Variable O & M is estimated to stay virtually unchanged at $4.3/MWh through October 2007 due to the increased value of the Canadian dollar during the period.