The Nanticoke Conversion Study

Prepared by Diener Consulting Inc. with assistance from:
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Environment Canada, Enwave District Energy,
The Salamander Foundation, Sithe,
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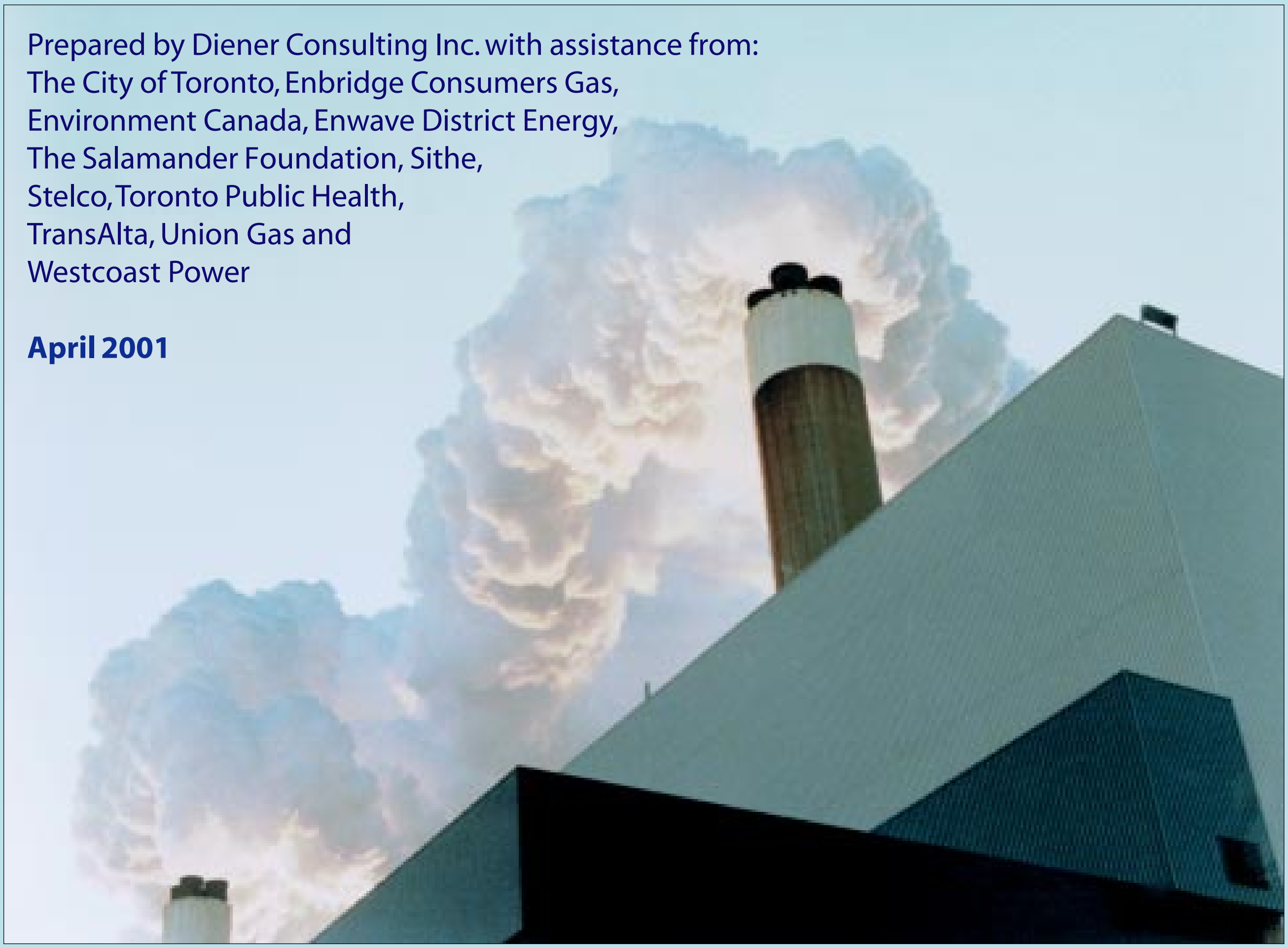

Ontario Clean Air Alliance

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About the OCAA: The OCAA is a coalition of health, environmental and consumer organizations, municipalities, utilities, faith communities, unions and individuals working for cleaner air through strict emission limits and the phase-out of coal in the electricity sector. Our member organizations represent over six million Ontarians.

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EXECUTIVE SUMMARY

Study Objectives

The study identifies the emission reduction benefits and financial costs of replacing Nanticoke's coal-fired boilers with new natural gas combined-cycle gas turbines (CCGTs) relative to continuing to operate Nanticoke as a coal-fired plant under the following coal technology scenarios:

(a) Reference Case: *Selective Catalytic Reduction* (*SCRs)* on 2 coal units ***(2SCR)*** - to reduce NOx emissions
(b) *SCRs* on 8 coal units (8SCR)
(c) (a) plus *flue gas desulphurization (FGD)* on 2 units ***(2SCR + 2SO₂)*** - to reduce SO_2 emissions
(d) (b) plus *FGD* on 8 units ***(8SCR + 8SO₂)***
(e) (c) plus *"bag house" with carbon injection* on 2 units to reduce emissions of mercury (Hg) and particulates (partic.) ***(2SCR + 2SO₂ + 2Hg+ 2partic.)***
(f) (d) plus *"bag house" with carbon injection* on 8 units ***(8SCR + 8SO₂ + 8Hg + 8partic.)***
(g) *combined-cycle natural gas turbines*

The analysis includes a base case set of data on fuel prices, retrofit costs, fuel efficiencies, annual capacity factors (ACFs) and other parameters, as well as four sensitivity cases involving lower and higher gas prices and two alternative ACFs higher than the base case value of 65 percent.

More specifically, the study determines the magnitude and unit costs of emission reductions by pollutant and scenario, as well as the net incremental costs of the gas plant case (g), taking into account the avoided costs of the coal cases shown above. These net costs are also expressed in terms of the bill impacts on various customer classes in Ontario. A further goal of the study was the development of an analytic model. The spreadsheet model is not a 'black box'; rather it serves as a tool that allows users to readily modify input data values and to test their impacts on the study results. The model is available upon request from the OCAA.

Methodology and Key Inputs

Planning Horizon. The study uses a 30-year planning horizon from early 2001 to 2030. This takes into account a 4-year construction period for the gas plant starting in early 2001 and ending in early 2005, and a similar timetable for the coal pollution control (PC) scenarios. It is also assumed that investments to maintain the life of the coal plant would be made during the period 2010 to 2021. The service life of the CCGT plant extends from early 2005 to 2030. The base year for discounting future cash flows is 2001. Hence the present value (PV) of costs refers to the PV in 2001. The real (inflation-adjusted) discount rate is 8 percent.

Gas Substitution Costs and Benefits. The *financial benefits* of gas-fired generation are the *avoided costs* associated with the displaced coal plant. These include fuel costs, operating and maintenance (O&M) costs, capital and annual O&M costs associated with the installation of pollution control technologies, and other capital expenditures, including those aimed at maintaining the operating life of the coal plant.

The *costs* of CCGT generation include the capital costs of the plant, its fuel costs, annual non-fuel O&M costs and the Ontario Power Generation (OPG) share of the costs of building the gas pipeline to Nanticoke. Consistent with the discount rate, all costs are expressed in real (inflation-adjusted) 2001 dollars. Note that as a "conservative" assumption, the gas scenario is not assigned benefits that stem from the avoided costs of coal plant shutdowns during the retrofit period.

The model provides outputs that include the following:

- costs (in PV terms) of each coal and gas scenario
- levelized unit energy cost (LUEC) of the gas plant (excluding the benefits of avoided costs)
- **net** cost of the gas plant relative to each of the six coal cases
- **net** LUEC or supply price of the gas plant relative to the coal cases (2001$ per kWh), where the net incremental costs are spread across all Ontario electricity consumers)
- bill impacts of the net incremental costs on various customer classes (supply prices as a percent of retail rates and monthly bill impact for average residential customer)
- annual and cumulative emissions of pollutants for each scenario
- annual and cumulative emission reductions by pollutant and scenario (in absolute and percentage terms)
- unit costs of emission reductions by pollutant and scenario

Environmental data used in the model include emission coefficients by pollutant and scenario (provided by OPG). Cost, price and engineering data include the capital and operating costs of each scenario, the heat rates (conversion efficiencies) and heat content of fuel used in each coal and gas scenario, the price of coal by scenario and Nanticoke's annual capacity factors. In the base case analysis, an ACF of 65 percent was used for the 4000 MW plant (based on OPG data). Coal and gas data were based on OPG and consultant estimates, respectively. Natural gas prices were estimated as follows. For the base case, the price of gas in 2005 was estimated by Enron Canada (in 2005US$). Converted to 2001 Canadian dollars, the price is $6.27 per thousand cubic feet (mcf). The gas price was assumed to stay constant in real terms thereafter. In the high price case, this price was escalated at 0.5 percent per year from 2005 to 2030. In the low price case, the analysis used estimates by Natural Resources Canada (NRCan): $3.85 in 2005 and $3.97

from 2010 to 2030. Section 2.2 and Tables 2.1 and 2.2 provide more details on the price, cost, emissions and engineering data used in the study.

Findings

Results of the base case analysis are shown in Tables 3.1 to 3.3. Key findings include the following:

- *Significant emission reductions achieved by switching to gas.* Emissions of mercury, particulates and ammonia fall by 100% across all coal cases. NO_2 emissions fall by 33% and 83% compared with the coal cases where eight and two coal units, respectively, are retrofitted. SO_2 levels are reduced by nearly 100% relative to all of the coal cases. Finally, CO_2 emissions are reduced by 61% across all coal cases. It is noteworthy that these reductions in CO_2 emissions would account for 31% of the total greenhouse gas reductions that are necessary for Ontario to meet its Kyoto target in 2010 (i.e, a 6% reduction in greenhouse gas emissions relative to the 1990 level).
- *Low unit energy costs and bill impacts associated with switching to gas*. In terms of LUECs, the net incremental cost of the gas plant ranges from 0.27 cents/kWh to 0.35 cents/kWh when compared with the most stringent coal case (f) and least stringent coal case (a), respectively. The bill impact of these costs on all customer classes varies from about 3.4% to 4.5% when compared with coal cases (f) and (a). In specific markets, the percent impacts on bills are 2.9 to 3.7 for the residential, 3.5 to 4.6 for the small commercial/industrial, and 4.9 to 6.4 for the large industrial rate classes. The monthly bill impact for an average residential consumer ranges from $2.29 to $2.99.
- *Reasonable Unit Costs in Achieving Emission Reductions.* The unit costs of achieving emission reductions relative to coal case (a) are $2,808 per tonne of NO_2, $849 per tonne of SO_2, $6 per tonne of CO_2, $1,327 per tonne of particulates and $78 per gram of mercury.
- *Modest Share of North American Gas Demand.* Switching Nanticoke to natural gas would result in incremental gas demand that represents about 0.6% of total North American consumption of gas in 2000.

Results of the sensitivity analysis are shown in Tables 3.4 to 3.13. In the low price scenario (Case S1), the monthly bill impact on households drops to a range of $0.99 to $1.69, when the gas option is compared with the most stringent (most costly) and least stringent (least costly) of the six coal cases. In the high price scenario (S2), the monthly bill impacts increase to a range of $2.44 to $3.15.

When a higher (constant base year) ACF of 70% is used (S3), the magnitude of emission reductions is greater; but the percent reductions remain unchanged. The reductions in CO_2 emissions represent 33% of the Kyoto target for Ontario (as discussed above). The net costs of gas conversion, the supply prices and bill impacts are slightly above those in the base case analysis. The monthly bill impacts range from \$2.47 to \$3.17. The higher annual gas consumption is only 0.65% of North American gas demand. Finally, in the case using a higher (80%) ACF (S4), there are greater reductions in emissions, and higher costs, supply prices and bill impacts relative to the other cases. Monthly bill impacts now range from \$2.84 to \$3.53. In the case of CO_2, the emission savings represent 38% of the Kyoto target for Ontario. Finally, the higher annual gas consumption is only 0.74% of North American gas demand.

1.0 INTRODUCTION

1.1 Background

Air pollution is a serious health problem. According to the Ontario Medical Association's report, *The Illness Costs of Air Pollution in Ontario*[1], air pollution costs Ontario more than $9.9 billion per year in health care costs, lost work time and other quantifiable expenses, as well as causing an estimated 1,900 premature deaths in Ontario each year.

Major contributors to air pollution emissions in Ontario are the five coal-fired power plants operated by Ontario Power Generation (OPG). The OCAA has noted that OPG's coal plants are responsible for 20%, 19%, 19% and 14% of the province's total emissions of sulphur dioxide, mercury, carbon dioxide and nitrogen oxides respectively. The Nanticoke Generating Station, on Lake Erie, is responsible for more than 50% of OPG's coal-fired electricity production.

On December 7, 2000 the Governments of Canada and the United States signed the *Ozone Annex to the 1991 Canada-United States Air Quality Agreement*. The *Ozone Annex* will require fossil power plants in southern Ontario to reduce their smog-causing nitrogen oxides emissions by approximately 50% by 2007. Ontario has two competing options to achieve compliance with the *Ozone Annex*: a) the replacement of some or all of its coal-fired boilers with high-efficiency, natural gas combined-cycle turbines; or b) the installation of selective catalytic reduction (SCR) units on some or all of its coal-fired units. OPG is proposing to work toward compliance with the *Ozone Annex* by installing SCRs on two of the Nanticoke Generation Station's eight coal-fired boilers and on two of the Lambton Generating Station's four coal-fired boilers.

As a result, there is a need to compare the emission benefits and financial costs of

[1] Ontario Medical Association, *The Illness Costs of Air Pollution in Ontario: A Summary of Findings*, (June 2000); URL: http://www.oma.org.

switching Nanticoke to natural gas versus continuing to operate it as a coal plant with different combinations of end-of-pipe control technologies.

1.2 Objectives

The study was designed to assess the emission reduction benefits and financial costs of replacing Nanticoke's coal-fired boilers with new natural gas combined-cycle gas turbines (CCGTs) [2] relative to continuing to operate Nanticoke as a coal-fired plant under the following coal technology scenarios:

(a) Reference Case: *SCRs* on 2 coal units ***(2SCR)***
(b) *SCRs* on 8 coal units (8SCR)
(c) (a) plus *flue gas desulphurization (FGD)* on 2 units ***(2SCR + 2SO₂)***
(d) (b) plus *FGD* on 8 units ***(8SCR + 8SO₂)***
(e) (c) plus *"bag house" with carbon injection* on 2 units to reduce emissions of mercury (Hg) and particulates (partic.) ***(2SCR + 2SO₂ + 2Hg+ 2partic.)***
(f) (d) plus *"bag house" with carbon injection* on 8 units ***(8SCR + 8SO₂ + 8Hg + 8partic.)***
(g) *combined-cycle natural gas turbines*

The analysis includes a base case set of data on fuel prices, retrofit costs, fuel efficiencies, annual capacity factors (ACFs) and other parameters, as well as four sensitivity cases involving lower and higher gas prices and two alternative assumptions concerning ACFs.

More specifically, the study was aimed at identifying the magnitude and unit costs of emission reductions by pollutant and scenario, as well as the net incremental costs of the gas plant case (g), taking into account the avoided costs of the coal cases shown above.

[2/]The study is "conservative" to the extent that natural gas plant is the only coal conversion option considered. There are of course other options that may achieve the emission reductions at an even lower cost than that associated with the CCGTs. These include, among others, demand management measures, as well as combined heat and power (cogeneration) and district heating/cooling systems.

These net costs were also to be expressed in terms of the bill impacts on various customer classes in Ontario. A further goal of the study was the development of the analytic model itself. The spreadsheet model was not to be a 'black box'; rather it was planned as a transparent analytic tool that would allow users to readily modify input data values and to test their impacts on the study results. The model is available upon request from the OCAA.

2.0 STUDY METHODOLOGY AND INPUT DATA

2.1 Methodology

Planning Horizon and Related Issues. The study uses a 30-year planning horizon extending from early 2001 to 2030. This takes into account a 4-year construction period for the gas plant starting in early 2001 and ending in early 2005, and a similar timetable for the coal pollution control (PC) scenarios. It is also assumed that investments to maintain the life of the coal plant would be made during the period 2010 to 2021. The service life of the CCGT plant extends from early 2005 to 2030. The base year for discounting future cash flows is 2001. Hence the present value (PV) of costs refers to the PV in 2001. The real (inflation-adjusted) discount rate is 8 percent.

Gas Substitution Costs and Benefits. The financial costs and benefits of switching from coal-fired to gas generation are defined as follows. The *financial benefits* of gas-fired generation are the *avoided costs* associated with the displaced coal plant. These include fuel costs, operating and maintenance (O&M) costs, capital and annual O&M costs associated with the installation of pollution control technologies, and other capital expenditures, including those aimed at maintaining the operating life of the coal plant.

The *costs* of CCGT generation include the capital costs of the plant, its fuel costs, annual non-fuel O&M costs and OPG's share of the costs of building the gas pipeline to Nanticoke. Consistent with the discount rate, all cost items are measured in real (inflation-adjusted) 2001 dollars. Note that as a "conservative" assumption, the gas scenario is not assigned benefits that stem from the avoided costs of coal plant shutdowns during the retrofit period.

Model Logic. For each of the coal and gas technology scenarios, the following spreadsheet algorithm was developed. The PV of costs is calculated based on the capital and operating costs of the particular scenario. Capital costs include the incremental investment outlays for pollution abatement and "life management" measures in the case of the coal scenarios. For the CCGT plant, the capital costs are simply the investment costs of the plant. In all cases, the capital dollars are spent over a multi-year period, using a cost distribution profile that can be varied by the model user.

Operating costs are separated into fuel and other O&M costs. Fuel costs are determined on the basis of the fuel requirements of the coal or gas plant multiplied by forecasts of delivered fuel prices. In the case of gas, delivered prices are determined in the model as the sum of the escalated commodity price plus the escalated price of applicable charges for distribution and storage. In turn, the fuel requirements are determined based on (i) the capacity of the Nanticoke plant times a schedule of annual capacity factors averaged over five-year intervals during the period 2001 to 2030, (ii) the heat rate applicable to each scenario (that is, the British thermal units or Btus of fuel required to generate a kWh of electricity), and (iii) the heat content of the coal or natural gas fuel applicable to each scenario.

In each scenario, this stream of annual cash flows from 2001 to 2030 is discounted back to 2001 to provide a PV of total costs. The net incremental cost of the gas plant (relative to a particular coal scenario) is computed as the difference in PVs associated with the gas plant and the particular coal scenario.

Gas plant *supply prices* are also calculated to determine the incremental costs per kWh of achieving reductions in the emissions of the various pollutants relative to each of the six coal cases. This supply price (in 2001$/kWh) is determined as the incremental PV cost of the scenario, divided by the PV of electricity consumption in Ontario over the period

2001 to 2030[3]. The supply prices are also shown as percentages of the average residential, commercial and industrial retail electricity prices in Ontario.

The impact of the incremental costs is expressed in terms of additional monthly electricity costs facing the typical Ontario household. Finally, the model also calculates the gross cost of the gas plant (excluding avoided costs); it is expressed in terms of its levelized unit energy cost (LUEC), showing the real (year 2001) dollar cost per kWh of electricity production.

The emission impacts of each scenario are assessed as follows. The model determines the annual and cumulative quantities of each pollutant based on emission coefficients applicable to each of the seven scenarios. The reductions achieved by the gas plant are compared to each of the six coal scenarios in both absolute and percentage terms. The model also calculates the PV cost per unit of cumulative (undiscounted) emission reductions, by scenario and pollutant, based on the shares of total cost allocated to each pollutant - an allocation formula that may be varied by the model user. The set of simulations carried out in the current study were based on the following allocations: NO_2 - 30%; SO_2 - 30%; CO_2 - 30%; mercury - 5%; and particulates - 5%.

2.2 Input Data

The range of data required by the spreadsheet model includes emission coefficients, current and forecast fuel prices, fuel heat rates, the heat content of fuels, capital costs, O&M costs (all determined for each of the seven cases) and plant capacity factors. Each of these data classes is briefly discussed below.

Emission Coefficients. For each scenario, OPG provided data on emission coefficients,

[3/] The Government of Ontario is planning to recover the cost of the former Ontario Hydro's stranded debt by levying a debt retirement charge of 0.7 cents per kilowatt-hour on virtually all electricity consumed in Ontario. The incremental cost of converting Nanticoke to natural gas could be recovered from all Ontario consumers in a similar manner. For more information on the Government of Ontario's debt retirement charge, see: Ontario Ministry of Energy, Science and Technology, *Power Switch: Update on Energy Competition in Ontario*, Vol. 3, Issue #2, June 9, 2000.

as shown in Table 2.1. Note that NO emissions are expressed as NO_2.

Coal Prices. In the reference case, the base period (year 2001) delivered price of coal is $46/tonne, using an average of the price range provided by OPG. In the remaining five coal scenarios, (involving progressively more stringent pollution controls), the coal price is $47/tonne. These prices are used in both the base case and the sensitivity cases. In all cases, the forecast values are based on projections made by Natural Resources Canada (NRCan) showing constant real coal prices over the planning horizon[4]. The complete set of data inputs is summarized in Table 2.2.

Natural Gas Prices. The left side of Chart 2.1 shows the New York Mercantile Exchange's (NYMEX's) wholesale natural gas spot prices from April 1990 to March 2001. From 1990 to 1999 natural gas prices averaged approximately $2 per thousand cubic feet (mcf) in U.S. dollars. However in the year 2000 wholesale gas prices rose dramatically and peaked at approximately $10 per mcf in late December 2000 and early January 2001. The rapid escalation in gas prices was a function of demand-side and supply-side factors. A booming North American economy, the desire by many companies to switch to a cleaner-burning fossil fuel and a colder than usual winter have all led to a rise in the demand for natural gas. Furthermore, in the short-term, gas supply was not able to keep up with the increase in demand for a number of reasons. First, in 1996 and 1997 high oil prices encouraged many companies to drill for oil instead of natural gas. Second, in 1998, low oil prices lead to reduced industry cash flow that limited all industry spending, including gas drilling.

However, during the first two months of 2001 the high gas prices have led to a drop in demand and a significant increase in gas drilling. As a result, by the end of February, natural gas spot prices had fallen by about 50 percent from their peak in late December and early January. Furthermore, the NYMEX futures market indicates that the market

[4/]See: Natural Resources Canada (NRCan), *Canada's Energy Outlook: 1996-2020, April 1997* and *Canada's Emissions Outlook: An Update*, December 1999, Ottawa.

expects gas prices to decline. Specifically, as of April 3, 2001, the March 2004 futures price for natural gas was $3.96 per mcf.

The delivered price is the sum of the gas commodity price at Dawn, Ontario (a widely used pricing point within Union Gas' system) plus applicable charges for distribution and storage. To forecast the year 2005 (in-service date) commodity price of natural gas, estimates were collected from several sources - those provided by Enron, a major energy commodity trader, served as the base case.

Enron has estimated that an indicative forward price for the year 2005 at Dawn would be $4.375 per mcf, in 2005 U.S. dollars[5]. Based on an exchange rate of $1.55, the Canadian dollar price is $6.78, in 2005 dollars. Deflating this by the estimated 8.1 percent growth in the Consumer Price Index from 2001 to 2005[6] yields a 2001 dollar price of 6.78/1.081, or $6.27/mcf. Beyond 2005, the base case analysis used a zero real rate of growth in gas prices.

In the low price sensitivity case (S1), the analysis used NRCan's forecasts, with a price of $3.85 in 2005 rising to $3.97 in 2010 and constant in real terms thereafter[7]. According to the Oil and Natural Gas Sub Table of Canada's National Climate Change Process, "increased competition, improved pipeline accessibility, the commoditization of natural gas, the greater use of storage capacity, technological advances and the sheer size of the resource base are expected to put pressure on prices from increasing substantially above this level."[8]

5/Communication from Ms. Marlene Cameron of Enron Canada, dated April 2, 2001.

6/Estimate provided by Mr. Marc Levesque of the TD Bank Economic Research Department, based on growth rates of 1.9% (2001 to 2002) and the Bank of Canada CPI target of 2% per year (2002 to 2005).

7/NRCan, 1999, op.cit. NRCan estimated the 2005 price at Henry Hub at $2.04 per mcf (in 1995US$). In 1995 Canadian dollars (1995C$), this price is $3.16 (using an exchange rate of 1.55). The 6-year CPI growth rate of 12% was then used to inflate this 1995C$ price to 2001C$ to yield a 2005 price of C$3.54 at Henry Hub. Finally, this price was converted to the Dawn price by adding C$0.31 (based on Union Gas estimates), resulting in a commodity price of $3.85. The 2010 price was calculated in a similar manner.

8/NRCan, 1999, op. cit., p.7.

In the sensitivity case involving high gas prices (S2), the base case price for 2005, as shown above, was escalated at a real rate of 0.50 percent per year.

To sum up, the year 2030 gas commodity price at Dawn is estimated to reach \$3.97, \$6.27 and \$7.10 in the low, medium and high price cases, respectively. In the base case projection, the charge to deliver the gas from Dawn to Nanticoke is estimated by Union Gas to be \$0.33/mcf in 2005, thereafter remaining constant in real terms. (Union's bundled distribution charges include storage services.) In the low and high price scenarios, the ratio of delivery charge to commodity price is assumed to be constant at the base case value of the ratio. This is a simplifying assumption as the actual charge would be based on costs and approval from the Ontario Energy Board.

Fuel Heat Rate and Heat Content. The heat rate applicable to CCGT plants is estimated to be 6,770 Btu/kWh, based on earlier work by the consultant. For coal plants, the heat rate is estimated by OPG to be 9,790 Btu/kWh in the reference scenario and slightly higher in the other coal pollution control scenarios. The heat content of natural gas is 1 million Btu/mcf and that of coal is 10,850 Btu/pound in the reference case. In the other scenarios, coal's heat content will be different if a different type of coal is required.

Capital and O&M Costs. The capital and O&M costs applicable to each of the seven scenarios are also shown in Table 2.2. The CCGT gas plant has an estimated cost of \$800,000/MW of capacity, based on engineering estimates for the 1998 study, as updated to late 2000. Similarly, gas plant O&M costs are estimated to be \$5.40/MWh. The OPG share of construction costs to build the distribution facilities at Nanticoke is \$54 million, based on a 65 percent load factor and estimates provided by Union Gas. In the sensitivity analysis involving a higher 80 percent load factor, the OPG share of construction cost is estimated to be \$45 million. Coal plant capital and O&M costs were estimated by OPG. Capital expenditures are required for both the pollution control measures reflected in each of the six coal scenarios and for life management activities undertaken between 2010 and 2021, as shown in Table 2.2.

Capacity Factors. Estimates of annual capacity factors (ACFs) were obtained from OPG. In the base year (2001), the ACF is 70 percent. The ACF data showed consistent averages of about 65 percent over successive 5-year intervals; hence the 65-percent figure was used in the base case analysis. The study also included sensitivity analysis to assess the impacts of higher ACFs. Cases S3 and S4 used the base year ACF of 70 percent and a higher ACF of 80 percent, respectively.

3.0 STUDY FINDINGS

3.1 Base Case Results

The emission reductions, financial costs and impacts and costs per unit of pollutant reduction are shown in Tables 3.1, 3.2 and 3.3. Note that throughout, the results refer to the emission and cost impacts of case (g) - the CCGT gas scenario - relative to each of the coal technology scenarios reflected in cases (a) through (f).

Emission Reductions. Switching to a gas-fired plant results in significant reductions in all of the pollutants under consideration. Emissions of mercury, particulates and ammonia fall by 100 percent across all coal cases. The gas option reduces NO_2 emissions by 33 percent and 83 percent compared with the coal cases where eight and two coal units, respectively, are retrofitted with pollution abatement technologies. SO_2 levels are reduced by nearly 100 percent relative to all of the coal cases. Finally, CO_2 emissions are reduced by a constant 61 percent across all coal cases, as none of the coal technologies involve CO_2 abatement. These CO_2 emissions reductions represent 31 percent of the total greenhouse gas reductions that are necessary for Ontario to meet its Kyoto target in 2010 (i.e., a 6 percent reduction in greenhouse gas emissions relative to the 1990 level) [9].

[9/]To reach the Kyoto target in 2010, Ontario must reduce its greenhouse gas emissions by 41,920,000 tonnes relative to its business as usual scenario. See: Analysis and Modelling Group, National Climate Change Process, Canada's Emissions Outlook: An Update (December 1999), p. C-30.

In the case of nitrogen oxides, SO_2 and mercury, the annual emission reductions achieved by the gas option relative to coal case (a) account for about 36, 66 and 29 percent respectively, of OPG's total emissions of these pollutants in 1999 from its six fossil plants[10]. Furthermore, coal case (a) already assumes an approximately 9,180 tonne reduction in nitrogen oxides (NO_2) due to the installation of SCRs. Therefore the gas option will reduce OPG's nitrogen oxides emissions by 48 percent relative to OPG's total 1999 nitrogen oxides emissions of its six fossil plants[11].

Financial Costs and Impacts. The gross unit cost of the gas plant (before counting the benefits of avoided coal plant costs) is 6.5 cents/kWh, measured in terms of levelized unit energy costs (LUECs). The cost components of this LUEC consist of capital (1.5 cents), fuel (4.5 cents) and non-fuel O&M (0.5 cents). The net incremental cost of the gas plant (measured in present value terms) ranges from $5.3 billion (relative to (f), the most stringent coal pollution abatement case) to $6.9 billion (relative to (a), the least stringent case). In terms of LUECs or supply prices, the net incremental cost of the gas plant ranges from 0.27 cents/kWh to 0.35 cents/kWh when compared with cases (f) and (a) respectively. These unit costs were determined under the assumption that all Ontario consumers would bear the net cost of the gas conversion project. The bill impact of these costs on all customer classes varies from about 3.4 to 4.5 percent. Turning to specific markets, the percent impacts on bills are 2.9 to 3.7 for the residential, 3.5 to 4.6 for the small commercial/industrial, and 4.9 to 6.4 for the large industrial rate classes.

Put another way, the monthly bill impact for an average residential customer varies from $2.29 to $2.99 when the gas plant is compared to cases (f) and (a) respectively. Note that the absolute surcharge could be varied by rate class to ensure that all customer classes experience the same percentage rate increase.

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[10]/In 1999, OPG's total NO_2, SO_2, and mercury emissions were, 78,900, 142,400 and 0.59 tonnes respectively. See: Ontario Power Generation, Towards Sustainable Development: 1999 Progress Report, pp. 12,50.

[11]/Ontario Power Generation, News Release, "Ontario Power Generation announces major environmental initiative", September 14, 2000.

Unit Costs of Pollution Reduction. As shown in Table 3.3, **t**he allocated shares of the PV of net costs for the gas plant were divided by the cumulative emission reductions to determine the unit cost of reducing each pollutant under each of the six coal scenarios. More generally, the analytic model used in the study can allocate these costs to each pollutant according to cost shares specified by a user and compute unit costs based on such allocation. The unit costs of achieving emission reductions relative to the coal reference case (a) are $2,808 per tonne of NO_2, $849 per tonne of SO_2, $6 per tonne of CO_2, $1,327 per tonne of particulates and $78 per gram of mercury.

Incremental Demand for Natural Gas. Starting in 2005, **t**he Nanticoke gas plant would require an annual quantum of natural gas amounting to 162 PJ. This demand represents about 0.6 percent of total North American consumption for gas in 2000[12].

3.2 Sensitivity Cases

Lower Gas Prices (Case S1). As noted in Section 2.2, the low gas price scenario was based on NRCan forecasts. The financial results associated with this case are shown in Tables 3.4 and 3.5. (The emission impacts are unchanged in this and the high price scenario.) The net costs and supply prices of the gas case are lower: incremental supply prices now range from 0.1 to 0.2 cents/kWh when the gas option is compared with cases (f) and (a) The monthly bill impact on households ranges from $0.99 to $1.69.

Higher Gas Prices (Case S2). As noted in Section 2.2, the high gas price scenario used the base case price for 2005 and a real rate of escalation of 0.5 percent per year thereafter. The financial results associated with this case are shown in Tables 3.6 and 3.7. The net costs and supply prices of the gas case are higher: incremental supply prices now range from 0.28 cents/kWh to 0.37 cents/kWh when the gas option is compared with cases (f) and (a). The monthly bill impacts increase to a range of $2.44 to $3.15 when the gas

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[12/]Total North American gas consumption in 2000 was approximately 27,300 PJ. See: *Canada's Emissions Outlook*, p. C-23; and *U.S. Energy Information Administration, Annual Energy Outlook 2001*, p. 127.

option is compared with the most stringent (most costly) and least stringent (least costly) of the six coal cases.

Constant (Base Year) Capacity Factor (Case S3). The emission reductions, financial impacts and unit costs of emission reductions associated with a constant 70-percent ACF are shown in Tables 3.8 to 3.10. Relative to the base case analysis, the magnitude of cumulative emission reductions is greater; but the percent reductions remain unchanged. The net costs of gas conversion, the supply prices and bill impacts are slightly above those in the reference case analysis. Supply prices range from 0.29 to 0.37 cents in cases (f) and (a) respectively, and the monthly bill impacts range from $2.47 to $3.17. Using the data and approach shown in Section 3.1, the CO_2 emission savings represent 33 percent of the Kyoto target for Ontario. The reductions in NO_2, SO_2 and mercury emissions represent 39, 71, and 31 percent respectively, of OPG's total emissions of these pollutants in 1999 from its six fossil plants. Furthermore, coal case (a) already assumes an approximately 9,180 tonne reduction in nitrogen oxides (NO_2) due to the installation of SCRs. Therefore the gas option will reduce OPG's nitrogen oxides emissions by 50 percent relative to OPG's total 1999 nitrogen oxides emissions of its six fossil plants. The higher annual gas consumption of about 174 PJ is only 0.65 percent of North American gas demand.

Higher (80%) Capacity Factor. (Case S4). The results of the analysis based on a higher 80-percent ACF are shown in Tables 3.11, 3.12 and 3.13. The findings are similar to those of Case S3 above, with somewhat greater reductions in emissions, and higher costs, supply prices and bill impacts relative to the base case analysis. Supply prices and monthly bill impacts now range from 0.33 to 0.41 cents and $2.84 to $3.53, respectively. In the case of CO_2, the emission savings represent 38 percent of the Kyoto target for Ontario. The reductions in NO_2, SO_2 and mercury emissions represent 44, 81, and 35 percent respectively, of OPG's total emissions of these pollutants in 1999 from its six fossil plants. Furthermore, coal case (a) already assumes an approximately 9,180 tonne reduction in nitrogen oxides (NO_2) due to the installation of SCRs. Therefore the gas option will reduce OPG's nitrogen oxides emissions by 56 percent relative to OPG's total

1999 nitrogen oxides emissions of its six fossil plants. Finally, the higher annual gas consumption of about 200 PJ is only 0.74 percent of North American gas demand.

TABLE 2.1

NANTICOKE COVERSION STUDY- Emission Coefficients (kg/MWh)

Scenarios	Pollution Control Technologies	NOx (as NO_2)[2]	SO_2	CO_2	Mercury (mg Hg per MWh)	Particulates	Ammonia
A	2SCR - BASE CASE (2 units retrofitted)	1.50	4.15	939.00	7.46	0.44	0.0038
B	8SCR (8 units retrofitted)	0.37	4.15	939.00	6.89	0.44	0.0052
C	2SCR + 2SO2	1.50	3.30	939.00	7.34	0.37	0.0038
D	8SCR + 8SO2	0.37	0.77	939.00	6.42	0.13	0.0052
E	2SCR + 2SO2 + 2Hg + 2partic.	1.50	3.30	939.00	6.18	0.04	0.0038
F	8SCR + 8SO2 + 8Hg + 8partic.	0.37	0.77	939.00	1.79	0.01	0.0052
G	NATURAL GAS CCGT	0.25	0.02	367.00	-	-	-

Notes:

[1] Based on OPG data. Maximum Continuous Rating (MCR) values were multiplied by 1.02 to yield average values at ACFs>60%

[2] NOx values provided by OPG as NO. These were converted to NO_2 by multiplying NO values by 1.53. Natural gas CCGT plant's value based on average of 0.108 and 0.21

TABLE 2.2

NANTICOKE CONVERSION STUDY - COST, PRICE & FUEL DATA

Scenarios Pollution Control	Coal Price (Base Yr) ($/tonne)	Coal Heat Content (BTU/Lb)	Fuel Heat rate (Btu/kWh)	Non-fuel O&M Cost Fixed ($/MW/Yr)	Non-fuel O&M Cost Variable ($/MWh)	Pollution Control (PC) Capital Cost (PCCC) ($M)	PCCC Distr'n (%,%,%)	PC O&M Cost/yr. (Fixed) ($/kW)	PC O&M Cost/yr. (Variable) ($/MWh)	Plant Life Mgt. Cap. Cost (PLMCC) ($/kW)	PLMCC, year(s) of expenditure (equal distr'n of spending over the years shown)
(a) REFERENCE CASE - SCRs on 2 units (2SCR)	46.00	10,850	9,790	25,000	1.35	120	35/55/10	0.45	0.25	3 200	2015 & 16 2010-11 & 2020-21
(b) SCRs on 8 units (8SCR)	46.00	10,850	9,800	25,000	1.35	480	15/35/35/15	1.70	1.05	12 200	2015 & 16 & 17 as in (a)
(c) 2SCR+SO2 controls on 2 units (2SO2)	47.00	11,390	9,820	25,000	1.35	420	10/15/35/40	2.25	0.45	7 200	2015 & 16 as in (a)
(d) 8SCR+8SO2	47.00	13,000	9,890	25,000	1.35	1,680	2/13/25/35/25	8.95	1.75	30 200	2015 & 16 & 17 as in (a)
(e) 2SCR+2SO2+2mercury (2Hg) + 2partic.	47.00	11,390	9,820	25,000	1.35	470	10/15/35/40	2.25	0.50	7 200	2015 & 16 as in (a)
(f) 8SCR+8SO2+8Hg + 8partic.	47.00	13,000	9,950	25,000	1.35	1,880	2/13/25/35/25	9.05	2.10	30 200	2015 & 16 & 17 as in (a)
(g) NATURAL GAS CC (4000 MW)			6,770		5.40						

"Global Data"

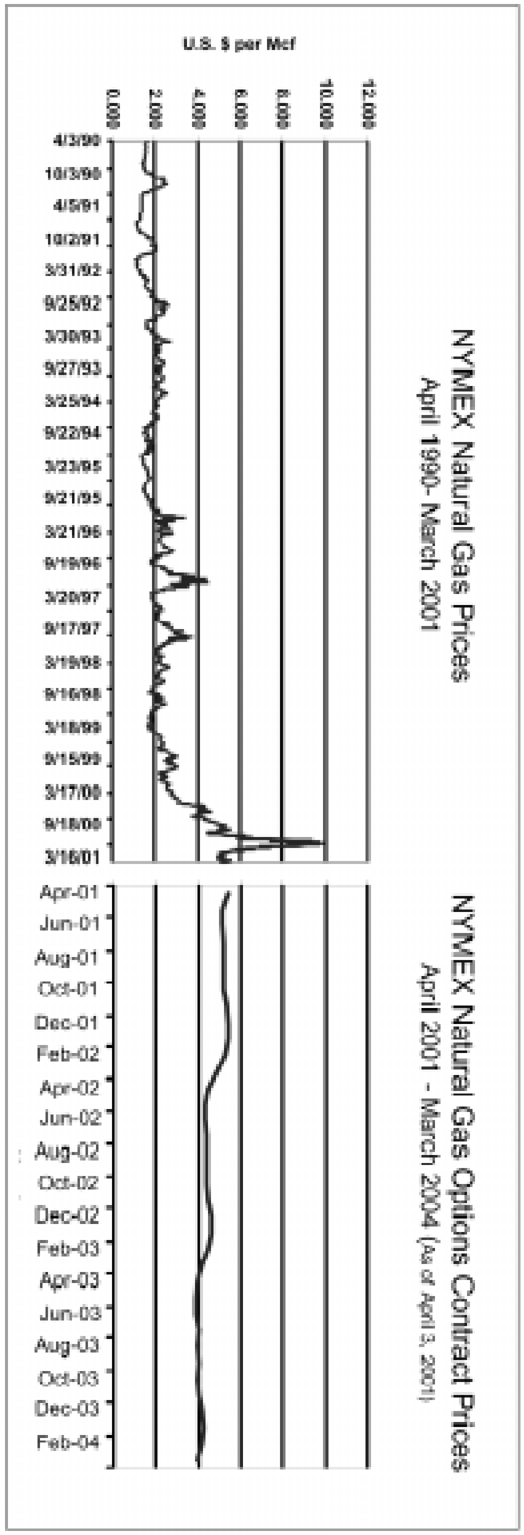
Electricity Prices (1998 cents/kWh) *		Yr. 2005 Commodity Gas Price at Dawn ($/mcf)	6.97
- residential	9.350		
- small com./ind.	7.536	Yr. 2005 Gas Storage, Transmission and	
- large (direct) ind.	5.474	Distribution (ST&D) Cost ($/mcf)	0.33
- all customers	7.740		

**Source: Ontario Power Generation, News Release, "Ontario Power Generation Notifies Customers of 2001 Rate Change, March 30, 2001 and Ontario Hydro, Final Annual Report, January 1998-March 1999, pp.65,66 and 68*

		Heat Content, Natural Gas	1 million/mcf
Nanticoke Capacity (MW)	4,000		
		Gas Plant Capital Cost ($ / kW)	800.00
Capacity Factor			
- Base Year (2001)	70.0%	Real Avg.Annual Gas Commodity Price	
- 2001-05 (avg.)	65.0%	Escal'n, 2005-30 (%)	0.0%
- 2006-10 "	65.0%		
- 2011-15 "	65.0%	Real Avg. Annual ST&D Cost	
- 2016-20 "	65.0%	Escal'n 2005-30 (%)	0.0%
- 2021-25 "	65.0%		
- 2026-30 "	65.0%	OPG Share Pipeline Capital Cost	$54 million
		Yr. Spent	2001-5
Real Discount Rate (%)	8.0%		(1/4 in each yr.)
Real Avg. Annual Coal Price Escal'n 2001-30 (%)	0.0%		

Natural Gas Prices

Chart 2.1



Nanticoke Conversion Evaluation - Base Case

Table 3.1

Emissions and Emission Reductions by Pollutant and Scenario

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES		Average Annual Emissions (2005-2030) Tonnes / Year (Mercury in kg / Year)	Annual Emission Reductions by Switching to Gas (2005-2030)	
Case / Scenario			Average Reduction Tonnes (Mercury in kg)	Percent
Case A	2SCR - BASE CASE (2 units retrofitted)			
	NO_2	34,122	28,428	83%
	SO_2	94,413	93,971	100%
	CO_2	21,386,664	13,027,872	61%
	Mercury	170	170	100%
	Particulates	10,021	10,021	100%
	Ammonia	87	87	100%
Case B	8SCR (8 units retrofitted)			
	NO_2	8,531	2,837	33%
	SO_2	94,413	93,971	100%
	CO_2	21,386,664	13,027,872	61%
	Mercury	157	157	100%
	Particulates	10,021	10,021	100%
	Ammonia	118	118	100%
Case C	2SCR + 2SO2			
	NO_2	34,122	28,428	83%
	SO_2	75,200	74,759	99%
	CO_2	21,386,664	13,027,872	61%
	Mercury	167	167	100%
	Particulates	8,427	8,427	100%
	Ammonia	87	87	100%
Case D	8SCR + 8SO2			
	NO_2	8,531	2,837	33%
	SO_2	17,540	17,098	97%
	CO_2	21,386,664	13,027,872	61%
	Mercury	146	146	100%
	Particulates	2,961	2,961	100%
	Ammonia	118	118	100%
Case E	2SCR + 2SO2 + 2Hg + 2partic.			
	NO_2	34,122	28,428	83%
	SO_2	75,200	74,759	99%
	CO_2	21,386,664	13,027,872	61%
	Mercury	141	141	100%
	Particulates	843	843	100%
	Ammonia	87	87	100%
Case F	8SCR + 8SO2 + 8Hg + 8partic.			
	NO_2	8,531	2,837	33%
	SO_2	17,540	17,098	97%
	CO_2	21,386,664	13,027,872	61%
	Mercury	41	41	100%
	Particulates	296	296	100%
	Ammonia	118	118	100%
Case G	NATURAL GAS CCGT			
	NO_2	5,694	n/a	n/a
	SO_2	441	n/a	n/a
	CO_2	8,358,792	n/a	n/a
	Mercury	0	n/a	n/a
	Particulates	0	n/a	n/a
	Ammonia	0	n/a	n/a

Nanticoke Conversion Evaluation - Base Case
Table 3.2
Net Present Value of Costs, Supply Prices and Cost Impacts

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES							
			Supply Price as a Percent of Retail Rates				Monthly Bill Impact
Case / Scenario	Present Value (PV) of Net Costs in 2001 - CDN$	Supply Price ($CDN / kWh, 2001) [a]	Residential $ 0.0935 / kWh	Small Commercial Industrial $ 0.0754 / kWh	Large Industrial $ 0.0547 / kWh	All Customers $ 0.0774 / kWh	for Average Residential Consumer [b]
Case A	$ 6,917,320,026	$ 0.00348 / kWh	3.72%	4.62%	6.36%	4.50%	$ 2.99 per Month
Case B	$ 6,419,203,250	$ 0.00323 / kWh	3.46%	4.29%	5.90%	4.17%	$ 2.78 per Month
Case C	$ 6,663,374,897	$ 0.00335 / kWh	3.59%	4.45%	6.13%	4.33%	$ 2.88 per Month
Case D	$ 5,540,826,328	$ 0.00279 / kWh	2.98%	3.70%	5.09%	3.60%	$ 2.40 per Month
Case E	$ 6,614,674,051	$ 0.00333 / kWh	3.56%	4.42%	6.08%	4.30%	$ 2.86 per Month
Case F	$ 5,293,678,519	$ 0.00266 / kWh	2.85%	3.54%	4.87%	3.44%	$ 2.29 per Month

Notes
[a] Across Domestic Electricity Consumption
[b] Average Residential Electricity Consumption: 860 kWh
(Source: Third Interim Report of the Market Design Committee to the Hon. Jim Wilson Minister of Energy, Science and Technology, October 1998, Appendix 2, p.8.)

Nanticoke Conversion Evaluation - Base Case
Table 3.3
Unit Cost of Pollution Reduction

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES						
	Present Value (PV) of	NPV Cost per Unit of Pollutant Saved (CDN$ / Tonne, Mercury is CDN$ / kg)				
Case / Scenario	Net Costs in 2001 - CDN$	NO_2	SO_2	CO_2	Mercury	Particulates
Allocation		30%	30%	30%	5%	5%
Case A	$ 6,917,320,026	$ 2,808	$ 849	$ 6	$ 78,292	$ 1,327
Case B	$ 6,419,203,250	$ 26,111	$ 788	$ 6	$ 78,665	$ 1,232
Case C	$ 6,663,374,897	$ 2,705	$ 1,028	$ 6	$ 76,651	$ 1,521
Case D	$ 5,540,826,328	$ 22,538	$ 3,739	$ 5	$ 72,872	$ 3,599
Case E	$ 6,614,674,051	$ 2,685	$ 1,021	$ 6	$ 90,373	$ 15,095
Case F	$ 5,293,678,519	$ 21,533	$ 3,572	$ 5	$ 249,703	$ 34,382

Nanticoke Conversion - Case S1: Lower Gas Price
Table 3.4
Net Present Value of Costs, Supply Prices and Cost Impacts

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES							
			Supply Price as a Percent of Retail Rates				Monthly Bill Impact
Case / Scenario	Present Value (PV) of Net Costs in 2001 - CDN$	Supply Price ($CDN / kWh, 2001) [a]	Residential $ 0.0935 / kWh	Small Commercial Industrial $ 0.0754 / kWh	Large Industrial $ 0.0547 / kWh	All Customers $ 0.0774 / kWh	for Average Residential Consumer [b]
Case A	$ 3,914,935,866	$ 0.00197 / kWh	2.11%	2.61%	3.60%	2.55%	$ 1.69 per Month
Case B	$ 3,416,819,090	$ 0.00172 / kWh	1.84%	2.28%	3.14%	2.22%	$ 1.48 per Month
Case C	$ 3,660,990,737	$ 0.00184 / kWh	1.97%	2.45%	3.37%	2.38%	$ 1.58 per Month
Case D	$ 2,538,442,168	$ 0.00128 / kWh	1.37%	1.70%	2.33%	1.65%	$ 1.10 per Month
Case E	$ 3,612,289,891	$ 0.00182 / kWh	1.94%	2.41%	3.32%	2.35%	$ 1.56 per Month
Case F	$ 2,291,294,359	$ 0.00115 / kWh	1.23%	1.53%	2.11%	1.49%	$ 0.99 per Month

Notes

[a] Across domestic electricity consumption

[b] Average residential electricity consumption: 860 kWh
(Source: Third Interim Report of the Market Design Committee to the Hon. Jim Wilson Minister of Energy, Science and Technology, October 1998, Appendix 2, p.8.)

Nanticoke Conversion - Case S1: Lower Gas Price
Table 3.5
Unit Cost of Pollution Reduction

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES						
	Present Value (PV) of	NPV Cost per Unit of Pollutant Saved (CDN$ / Tonne, Mercury is CDN$ / kg)				
Case / Scenario	Net Costs in 2001 - CDN$	NO_2	SO_2	CO_2	Mercury	Particulates
Allocation		30%	30%	30%	5%	5%
Case A	$ 3,914,935,866	$ 1,589	$ 481	$ 3	$ 44,310	$ 751
Case B	$ 3,416,819,090	$ 13,899	$ 420	$ 3	$ 41,872	$ 656
Case C	$ 3,660,990,737	$ 1,486	$ 565	$ 3	$ 42,114	$ 835
Case D	$ 2,538,442,168	$ 10,326	$ 1,713	$ 2	$ 33,385	$ 1,649
Case E	$ 3,612,289,891	$ 1,466	$ 558	$ 3	$ 49,353	$ 8,243
Case F	$ 2,291,294,359	$ 9,320	$ 1,546	$ 2	$ 108,080	$ 14,882

Nanticoke Conversion - Case S2: Higher Gas Price

Table 3.6

Net Present Value of Costs, Supply Prices and Cost Impacts

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES							
			Supply Price as a Percent of Retail Rates				Monthly Bill Impact
Case / Scenario	Present Value (PV) of Net Costs in 2001 - CDN$	Supply Price ($CDN / kWh, 2001) [a]	Residential $ 0.0935 / kWh	Small Commercial Industrial $ 0.0754 / kWh	Large Industrial $ 0.0547 / kWh	All Customers $ 0.0774 / kWh	for Average Residential Consumer [b]
Case A	$ 7,269,687,938	$ 0.00366 / kWh	3.91%	4.86%	6.68%	4.73%	$ 3.15 per Month
Case B	$ 6,771,571,162	$ 0.00341 / kWh	3.65%	4.52%	6.23%	4.40%	$ 2.93 per Month
Case C	$ 7,015,742,809	$ 0.00353 / kWh	3.78%	4.69%	6.45%	4.56%	$ 3.04 per Month
Case D	$ 5,893,194,240	$ 0.00297 / kWh	3.17%	3.94%	5.42%	3.83%	$ 2.55 per Month
Case E	$ 6,967,041,963	$ 0.00351 / kWh	3.75%	4.65%	6.41%	4.53%	$ 3.02 per Month
Case F	$ 5,646,046,431	$ 0.00284 / kWh	3.04%	3.77%	5.19%	3.67%	$ 2.44 per Month

Notes

[a] Across domestic electricity consumption

[b] Average residential electricity consumption: 860 kWh

(Source: Third Interim Report of the Market Design Committee to the Hon. Jim Wilson Minister of Energy, Science and Technology, October 1998, Appendix 2, p.8.)

Nanticoke Conversion - Case S2: Higher Gas Price

Table 3.7

Unit Cost of Pollution Reduction

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES						
	Present Value (PV) of	NPV Cost per Unit of Pollutant Saved (CDN$ / Tonne, Mercury is CDN$ / kg)				
Case / Scenario	Net Costs in 2001 - CDN$	NO_2	SO_2	CO_2	Mercury	Particulates
Allocation		30%	30%	30%	5%	5%
Case A	$ 7,269,687,938	$ 2,951	$ 893	$ 6	$ 82,280	$ 1,395
Case B	$ 6,771,571,162	$ 27,545	$ 831	$ 6	$ 82,983	$ 1,299
Case C	$ 7,015,742,809	$ 2,848	$ 1,083	$ 6	$ 80,704	$ 1,601
Case D	$ 5,893,194,240	$ 23,972	$ 3,977	$ 5	$ 77,506	$ 3,828
Case E	$ 6,967,041,963	$ 2,828	$ 1,075	$ 6	$ 95,187	$ 15,899
Case F	$ 5,646,046,431	$ 22,966	$ 3,810	$ 5	$ 266,324	$ 36,671

Nanticoke Conversion - Case S3: 70% ACF

Table 3.8

Emissions and Emission Reductions by Pollutant and Scenario

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES			
	Average Annual Emissions (2005-2030)	Annual Emission Reductions by Switching to Gas (2005-2030)	
Case / Scenario	Tonnes / Year (Mercury in kg / Year)	Average Reduction Tonnes (Mercury in kg)	Percent
Case A 2SCR - BASE CASE (2 units retrofitted)			
NO_2	36,747	30,615	83%
SO_2	101,675	101,200	100%
CO_2	23,031,792	14,030,016	61%
Mercury	183	183	100%
Particulates	10,792	10,792	100%
Ammonia	93	93	100%
Case B 8SCR (8 units retrofitted)			
NO_2	9,187	3,055	33%
SO_2	101,675	101,200	100%
CO_2	23,031,792	14,030,016	61%
Mercury	169	169	100%
Particulates	10,792	10,792	100%
Ammonia	128	128	100%
Case C 2SCR + 2SO2			
NO_2	36,747	30,615	83%
SO_2	80,985	80,510	99%
CO_2	23,031,792	14,030,016	61%
Mercury	180	180	100%
Particulates	9,075	9,075	100%
Ammonia	93	93	100%
Case D 8SCR + 8SO2			
NO_2	9,187	3,055	33%
SO_2	18,889	18,414	97%
CO_2	23,031,792	14,030,016	61%
Mercury	157	157	100%
Particulates	3,189	3,189	100%
Ammonia	128	128	100%
Case E 2SCR + 2SO2 + 2Hg + 2partic.			
NO_2	36,747	30,615	83%
SO_2	80,985	80,510	99%
CO_2	23,031,792	14,030,016	61%
Mercury	152	152	100%
Particulates	908	908	100%
Ammonia	93	93	100%
Case F 8SCR + 8SO2 + 8Hg + 8partic.			
NO_2	9,187	3,055	33%
SO_2	18,889	18,414	97%
CO_2	23,031,792	14,030,016	61%
Mercury	44	44	100%
Particulates	319	319	100%
Ammonia	128	128	100%
Case G NATURAL GAS CCGT			
NO_2	6,132	na	na
SO_2	475	na	na
CO_2	9,001,776	na	na
Mercury	0	na	na
Particulates	0	na	na
Ammonia	0	na	na

Nanticoke Conversion - Case S3: 70% ACF

Table 3.9

Net Present Value of Costs, Supply Prices and Cost Impacts

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES							
			Supply Price as a Percent of Retail Rates				Monthly Bill Impact
Case / Scenario	Present Value (PV) of Net Costs in 2001 - CDN$	Supply Price ($CDN / kWh, 2001) [a]	Residential $ 0.0935 / kWh	Small Commercial Industrial $ 0.0754 / kWh	Large Industrial $ 0.0547 / kWh	All Customers $ 0.0774 / kWh	for Average Residential Consumer [b]
Case A	$ 7,332,219,491	$ 0.00369 / kWh	3.95%	4.90%	6.74%	4.77%	$ 3.17 per Month
Case B	$ 6,822,700,497	$ 0.00343 / kWh	3.67%	4.56%	6.27%	4.44%	$ 2.95 per Month
Case C	$ 7,081,657,341	$ 0.00356 / kWh	3.81%	4.73%	6.51%	4.61%	$ 3.07 per Month
Case D	$ 5,970,863,631	$ 0.00301 / kWh	3.21%	3.99%	5.49%	3.88%	$ 2.58 per Month
Case E	$ 7,032,260,455	$ 0.00354 / kWh	3.79%	4.70%	6.47%	4.57%	$ 3.04 per Month
Case F	$ 5,717,484,662	$ 0.00288 / kWh	3.08%	3.82%	5.26%	3.72%	$ 2.47 per Month

Notes

[a] Across domestic electricity consumption

[b] Average residential electricity consumption: 860 kWh
(Source: Third Interim Report of the Market Design Committee to the Hon. Jim Wilson Minister of Energy, Science and Technology, October 1998, Appendix 2, p.8.)

Nanticoke Conversion - Case S3: 70% ACF

Table 3.10

Coal Technology Costs and Supply Prices

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES						
	Present Value (PV) of	NPV Cost per Unit of Pollutant Saved (CDN$ / Tonne, Mercury is CDN$ / kg)				
Case / Scenario	Net Costs in 2001 - CDN$	NO_2	SO_2	CO_2	Mercury	Particulates
Allocation		30%	30%	30%	5%	5%
Case A	$ 7,332,219,491	$ 2,763	$ 836	$ 6	$ 77,060	$ 1,307
Case B	$ 6,822,700,497	$ 25,770	$ 778	$ 6	$ 77,638	$ 1,216
Case C	$ 7,081,657,341	$ 2,669	$ 1,015	$ 6	$ 75,644	$ 1,501
Case D	$ 5,970,863,631	$ 22,553	$ 3,741	$ 5	$ 72,918	$ 3,601
Case E	$ 7,032,260,455	$ 2,650	$ 1,008	$ 6	$ 89,216	$ 14,901
Case F	$ 5,717,484,662	$ 21,596	$ 3,583	$ 5	$ 250,430	$ 34,482

Nanticoke Conversion - Case S4: 80% ACF

Table 3.11

Emissions and Emission Reductions by Pollutant and Scenario

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES				
Case / Scenario		Average Annual Emissions (2005-2030) Tonnes / Year (Mercury in kg / Year)	Annual Emission Reductions by Switching to Gas (2005-2030)	
			Average Reduction Tonnes (Mercury in kg)	Percent
Case A	2SCR - BASE CASE (2 units retrofitted)			
	NO_2	41,997	34,989	83%
	SO_2	116,200	115,657	100%
	CO_2	26,322,048	16,034,304	61%
	Mercury	209	209	100%
	Particulates	12,334	12,334	100%
	Ammonia	107	107	100%
Case B	8SCR (8 units retrofitted)			
	NO_2	10,499	3,491	33%
	SO_2	116,200	115,657	100%
	CO_2	26,322,048	16,034,304	61%
	Mercury	193	193	100%
	Particulates	12,334	12,334	100%
	Ammonia	146	146	100%
Case C	2SCR + 2SO2			
	NO_2	41,997	34,989	83%
	SO_2	92,554	92,011	99%
	CO_2	26,322,048	16,034,304	61%
	Mercury	206	206	100%
	Particulates	10,372	10,372	100%
	Ammonia	107	107	100%
Case D	8SCR + 8SO2			
	NO_2	10,499	3,491	33%
	SO_2	21,587	21,044	97%
	CO_2	26,322,048	16,034,304	61%
	Mercury	180	180	100%
	Particulates	3,644	3,644	100%
	Ammonia	146	146	100%
Case E	2SCR + 2SO2 + 2Hg + 2partic.			
	NO_2	41,997	34,989	83%
	SO_2	92,554	92,011	99%
	CO_2	26,322,048	16,034,304	61%
	Mercury	173	173	100%
	Particulates	1,037	1,037	100%
	Ammonia	107	107	100%
Case F	8SCR + 8SO2 + 8Hg + 8partic.			
	NO_2	10,499	3,491	33%
	SO_2	21,587	21,044	97%
	CO_2	26,322,048	16,034,304	61%
	Mercury	50	50	100%
	Particulates	364	364	100%
	Ammonia	146	146	100%
Case G	NATURAL GAS CCGT			
	NO_2	7,008	na	na
	SO_2	543	na	na
	CO_2	10,287,744	na	na
	Mercury	0	na	na
	Particulates	0	na	na
	Ammonia	0	na	na

Nanticoke Conversion - Case S4: 80% ACF

Table 3.12

Net Present Value of Costs, Supply Prices and Cost Impacts

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES							
			Supply Price as a Percent of Retail Rates				Monthly Bill Impact
Case / Scenario	Present Value (PV) of Net Costs in 2001 - CDN$	Supply Price ($CDN / kWh, 2001) [a]	Residential $ 0.0935 / kWh	Small Commercial Industrial $ 0.0754 / kWh	Large Industrial $ 0.0547 / kWh	All Customers $ 0.0774 / kWh	for Average Residential Consumer [b]
Case A	$ 8,154,566,135	$ 0.00410 / kWh	4.39%	5.45%	7.50%	5.30%	$ 3.53 per Month
Case B	$ 7,622,242,706	$ 0.00384 / kWh	4.10%	5.09%	7.01%	4.96%	$ 3.30 per Month
Case C	$ 7,910,769,943	$ 0.00398 / kWh	4.26%	5.28%	7.27%	5.14%	$ 3.42 per Month
Case D	$ 6,823,485,951	$ 0.00343 / kWh	3.67%	4.56%	6.27%	4.44%	$ 2.95 per Month
Case E	$ 7,859,980,979	$ 0.00396 / kWh	4.23%	5.25%	7.23%	5.11%	$ 3.40 per Month
Case F	$ 6,557,644,662	$ 0.00330 / kWh	3.53%	4.38%	6.03%	4.26%	$ 2.84 per Month

Notes

[a] Across domestic electricity consumption

[b] Average residential electricity consumption: 860 kWh

(Source: Third Interim Report of the Market Design Committee to the Hon. Jim Wilson Minister of Energy, Science and Technology, October 1998, Appendix 2, p.8.)

Nanticoke Conversion - Case S4: 80% ACF

Table 3.13

Coal Technology Costs and Supply Prices

GAS CASE RELATIVE TO COAL TECHNOLOGY CASES						
	Present Value (PV) of	NPV Cost per Unit of Pollutant Saved (CDN$ / Tonne, Mercury is CDN$ / kg)				
Case / Scenario	Net Costs in 2001 - CDN$	NO_2	SO_2	CO_2	Mercury	Particulates
Allocation		30%	30%	30%	5%	5%
Case A	$ 8,154,566,135	$ 2,689	$ 814	$ 6	$ 74,990	$ 1,271
Case B	$ 7,622,242,706	$ 25,191	$ 760	$ 5	$ 75,894	$ 1,188
Case C	$ 7,910,769,943	$ 2,609	$ 992	$ 6	$ 73,938	$ 1,467
Case D	$ 6,823,485,951	$ 22,552	$ 3,741	$ 5	$ 72,914	$ 3,601
Case E	$ 7,859,980,979	$ 2,592	$ 986	$ 6	$ 87,252	$ 14,573
Case F	$ 6,557,644,662	$ 21,673	$ 3,596	$ 5	$ 251,326	$ 34,606