Control Technologies Review, Cogeneration Units

Prepared For

Clean Air Strategic Alliance

February 2010

JACOBS Consultancy

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Executive Summary

The Clean Air Strategic Alliance (CASA) commissioned Jacobs Consultancy Inc. ("Jacobs Consultancy") to study the status of NOx control technologies for non-peaking gas-fired turbines, based on the performance of control technologies, current operating knowledge, and recent approval/permit limits in other jurisdictions. CASA intends to use this information to update the current emission limits for nitrogen oxides (NOx) for new generation in Alberta, based on Best Available Technology Economically Achievable (BATEA).

Previous to this study, CASA had already carried out a broad control technology review on gas turbine operation for electrical power generation. The objective of the study was to: 1) generate information specific to gas-fired cogeneration units; and 2) determine the best available control technology economically achievable (BATEA) for NOx emissions control for gas-fired cogeneration units.

Jacobs Consultancy carried out the following activities to achieve study objectives:

- Control Technology Review— Capital and operating cost estimates were made for various NOx control technologies and the cost effectiveness of the technologies were calculated
- Alternate Fuels Review— The team gathered information about the impact of firing with fuels other than natural gas on the effectiveness of NOx control technology
- Heat Recovery Allowance— Commentary was provided on the types of duct burner available, their NOx generation, and industry experience with newer low NOx technology. Sensitivity analyses were performed on the heat recovery and NOx generation with duct firing, and a methodology derived to calculate an output based heat recovery allowance assuming a control technology of choice.
- Jurisdictional Review—The team researched the legislation covering NOx emissions outside Alberta and compiled the data for comparison with local regulations

These analyses resulted in the following conclusions:

- *The use of Dry Low NOx (DLN) burners is "cost effective"*—Relative to the previous generation diffusion burners, DLN burners achieve significant NOx emissions reduction. However, their use is not appropriate where high hydrogen content fuels are used.
- *The use of selective catalytic reduction (SCR) to further reduce NOx can be cost effective in larger installations*—Use of NH3 in the SCR presents safety and operational risk, however these risks have been safely handled in a large number of installations.

Definitions of Terms and Abbreviations

The following are acronyms, abbreviations, and symbols used in this report:

AENV	Alberta Environment
AERI	Alberta Energy Research Institute
AESO	Alberta Electric System Operator
BATEA	Best Available Technology Economically Achievable
BACTEA	Best Available Control Technology Economically Achievable
BFD	Block Flow Diagram
Btu	British Thermal Unit
CAD	Canadian Dollars
CAPEX	Capital Expenditures
CASA	Clean Air Strategic Alliance
CCS	Carbon Capture and Sequestration
CEMS	Continuous Emissions Monitoring Systems
CO_2	Carbon Dioxide
cSt	Centistokes
CWE	Cold Water Equivalent
DLN	Dry Low NOx
DOE	Department of Energy
EPCM	Engineering, Procurement and Construction Management
EPRI	Energy Petroleum Research Institute
ERCB	Energy Resources Conservation Board
FGD	Flue Gas Desulphurization
GJ	Gigajoule
Gpm	Gallons per minute
Hg	Mercury
HHV	Higher Heating Value
IRR	Internal Rate of Return
KBPD	Thousand Barrels per Day
KLB/hr	Thousand Pounds per Hour
kW	Kilowatts
kWh	Kilowatt Hour
LAER	Lowest Achievable Emission Rate, is required on major new or modified sources in USEPA non-attainment areas
LHV	Lower Heating Value
LT/D	Long Tons per Day
MMBtu	Million British Thermal Units
MMSCF	Millions Standard Cubic Feed
MW	Megawatts
MWh	Megawatt hours
NH3	Ammonia
NOx	Nitrogen Oxide compounds
NPV	Net Present Value
OTSG	Once Through Steam Generator
OPEX	Operating Expenditures
PM	Particulate Matter (emitted from a combustion source)
ppmv	Parts per Million by volume
psig	Pounds per Square Inch Gauge
RACT	Reasonably Available Control Technology, is required on existing sources in areas that are not meeting USEPA ambient air quality standards (i.e., non-attainment areas)
SAGD	Steam Assisted Gravity Drainage

SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SOR	Steam to Oil Ratio
SOx	Sulfur Dioxide and Tri-Oxide collectively
t	Tonne (1000 kg)
ULNB	Ultra-Low NOx Burners
USEPA	United States Environmental Protection Agency
wppm	Parts per Million by weight

Section A.

Introduction

Background

The Clean Air Strategic Alliance (CASA) is a non-profit association composed of stakeholders from three sectors – government, industry and non-government organizations such as health and environmental groups. All CASA groups and teams, including the board of directors, make decisions and recommendations by consensus. These recommendations are expected to be more innovative and longer lasting than those reached through traditional negotiation processes. CASA's vision is that the air will be odourless, tasteless, look clear and have no measurable short- or long-term adverse effects on people, animals or the environment.

In 2003, CASA used a collaborative approach to produce "An Emissions Management Framework for the Alberta Electricity Sector". To ensure continuous improvement and keep the Framework timely and relevant, a key recommendation was that a multi-stakeholder review be done every five years. A new project team was formed in June 2007 to undertake the first five year review.

CASA engaged a consultant, Eastern Research Group, Inc., to make a determination of the Best Available Technology Economically Achievable (BACTEA) for emission control in greenfield electricity generating facilities in Alberta. The BACTEA analysis was conducted for technologies used to reduce the emissions of four pollutants: nitrogen oxides (NOx), sulfur dioxide (SO_2), particulate matter (PM), and mercury (Hg). Subsequent to completion of the report, CASA decided that further analysis was needed to focus specifically on the unique economic and operational issues surrounding NOx control in cogeneration facilities, especially those integrated with industrial plants such as refineries, chemical plants, upgraders, and bitumen production facilities.

CASA engaged Jacobs to perform the latter analysis.

Cogeneration in Alberta

The term "cogeneration" refers to a process that is a source of both heat and power. Typically, in the Alberta context, a natural gas-fired turbine turns a generator and the exhaust heat is recovered by generating steam. Cogeneration has enjoyed strong growth in Alberta since the power generation market was deregulated in 1995. The ability to access the market and the abundance of industrial facilities with steam demand have driven the market such that gas fired cogeneration has grown by over 3100 MW since deregulation(1), accounting for 60% of the growth in total generation capacity over that timeframe. In particular, the application of cogeneration to produce steam for in-situ heavy oil production has been an area where there has been significant investment.

Figure A.1 shows that cogeneration capacity grew rapidly in the years immediately following deregulation but has since moderated. The growth rate in Alberta is strongly influenced by the activity level in the oil sands industry.

Figure A.1 - Growth of Alberta Cogeneration Capacity

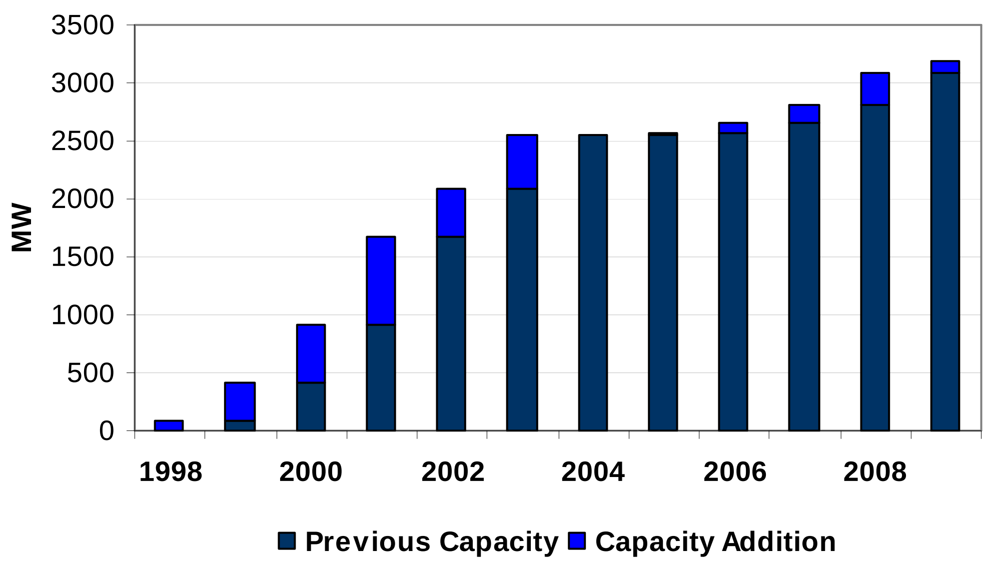
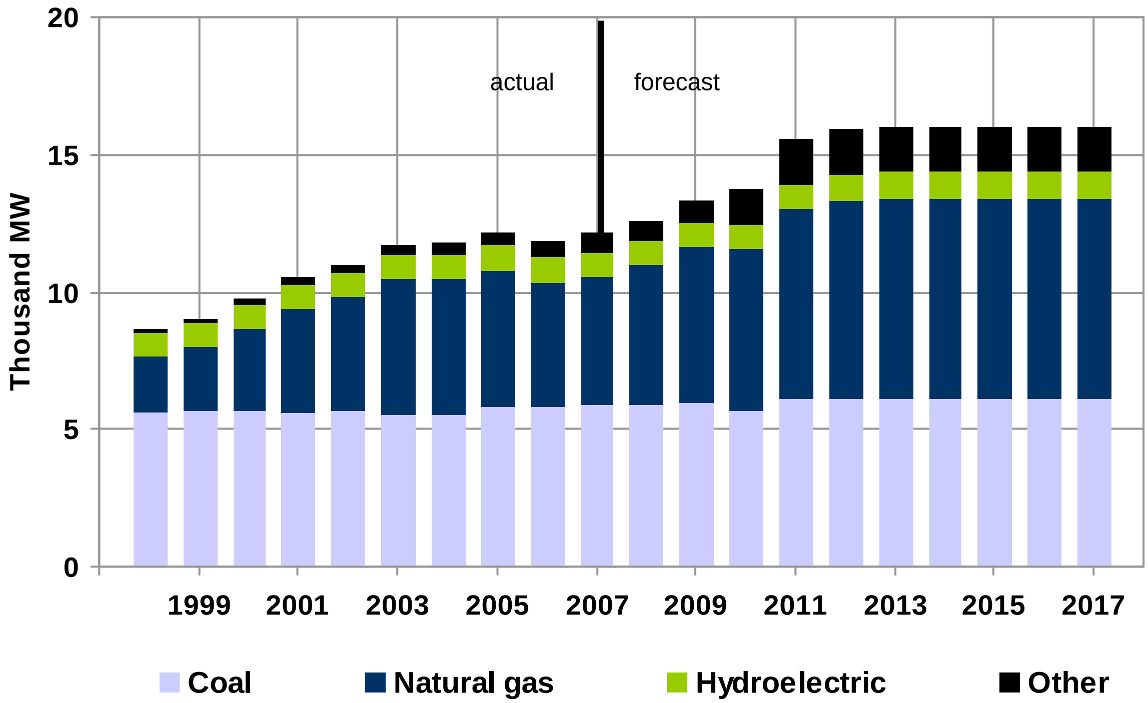


Figure A.2 is from the Energy Resources Conservation Board (ERCB) report "Alberta's Energy Reserves and Supply/Demand Outlook 2009-2018". It shows that natural gas-fired cogeneration capacity has gained on other sources of electrical power since deregulation and is expected to grow in importance over the period of the forecast. The natural gas-fired component shown in the figure includes 1600MW of cogeneration capacity, most of which will be sited in the Municipal District of Wood Buffalo[2].

Figure A.2 - Alberta Electricity Generating Capacity



Reference: Andy Burrowes, Rick Marsh, Curtis Evans, Michael Teare, Sharleen Ramos, Farhood Rahnama, Marie-Anne Kirsch, LeMoine Philp, Joanne Stenson, Mussie Yemane, Judy Van Horne, Joseph Fong, Greig Sankey, and Pat Harrison, "Alberta's Energy Reserves and Supply/Demand Outlook 2009-2018", ERCB, June 2009

It is instructive to examine the economic reasons for the growth in cogeneration capacity as the economic benefits may be affected by the NOx control technologies that will be described later in this report. Therefore, Jacobs was asked to present the relative costs of cogeneration and standalone steam generation. Table A.1 compares the annual costs of operating a cogeneration facility to those of operating once through steam generators (OTSGs) with a similar steam output. The examples shown are based on the case of a SAGD operator with nominal behind the fence electrical demand of 85 MW and steam demand of 541 tonne per hour, firing natural gas as fuel. The capital costs used for the basic cogeneration facility and the

OTSG are based on estimates that Jacobs Engineering has done for similar size plants. The capital costs used for the NOx control equipment were developed as part of this study as described in Section B of this report.

The unit costs for steam and power were calculated by allocating the annual costs to power and steam production in the same proportion as the fuel gas fired in the turbine and the duct. In the example shown, 70% of the gas is fired in the turbine and the remainder in the duct. Therefore, 70% of the annual costs were allocated to power production and the remainder to steam production.

Other assumptions used in the comparison are:

- Natural gas price is 5.25 Canadian Dollars (CAD)/ GJ higher heating value (HHV) basis(3)
- Power price is 0.0712 CAD /kWh(1)
- The power user qualifies for Price Schedule D31 of the ATCO Distribution Tariff
- Facilities are located in north eastern Alberta
- Payroll costs for operations personnel are 150,000 CAD/ year
- Maintenance costs are 5% of bare equipment costs
- Cost of capital is 12% for turbines and OTSG
- Cost of capital is 8% for NOx control equipment
- Equipment life is 25 years for turbines and OTSG
- Equipment life is 15 years for NOx control equipment
- The service factor for both options is 95%

Table A.1 – Cost Comparisons for 85MW Cogeneration and OTSG

		Cogen With DLN	Cogen With SCR	OTSG
CAPEX	*Millions CAD*	*166*	*178*	*85*
Annualized CAPEX	Million CAD/year	21	23	11
OPEX	Million CAD/year	69	70	34
Purchased Power	Million CAD/year	0	0	51
Transmission Cost	Million CAD/year	0	0	13[(4)]
TOTALS		**90**	**93**	**108**
Unit Power Cost	CAD / kWh	**0.089**	**0.091**	**0.090**
Unit Steam Cost	CAD / tonne	**6.04**	**6.21**	**9.87**

This analysis, based on the current natural gas price, indicates an advantage for cogeneration. Economic evaluations in the industry are often done with the assumption that commodity prices escalate over time. Any increase in the prices of natural gas or power relative to those used in this example will increase the economic attractiveness of cogeneration. Also, industrial operators sometimes give consideration to the perceived increase in reliability of electrical supply that comes with self generation.

With the economic attractiveness and potential for future growth of cogeneration, it will be important to ensure that the right emission limits are in place to adequately protect air quality in Alberta. The intent of this report is to generate information that CASA can use to make recommendations regarding the emission limits for NOx from new generating facilities.

Study Objectives

The objectives of the Study are as follows:

- Determine the cost effectiveness of Dry Low NOx burners and Selective Catalytic Reduction at removing NOx
- Provide information on the performance of NOx control technologies when firing fuels other than sales-grade natural gas
- Suggest a methodology by which a regulatory body might set a "Heat Recovery Allowance" that would allow that body to promote energy efficiency while regulating emissions
- Provide information on cogeneration NOx control regulations from other jurisdictions to allow the recommendation for Alberta to be considered in a global context

References

1) Alberta Energy Website (http://www.energy.gov.ab.ca/Electricity/682.asp)
2) Andy Burrowes, Rick Marsh, Curtis Evans, Michael Teare, Sharleen Ramos, Farhood Rahnama, Marie-Anne Kirsch, LeMoine Philp, Joanne Stenson, Mussie Yemane, Judy Van Horne, Joseph Fong, Greig Sankey, and Pat Harrison, "Alberta's Energy Reserves and Supply/Demand Outlook 2009-2018", ERCB, June 2009
3) TMX website www.ngx.com accessed on Jan 21, 2010
4) Price Schedule D31, "2010 Interim Distribution Tariff and Transmission Facility Owner's Tariff", ATCO Electric Ltd.

Section B.

NOx Control Technology Review

Technology And Economics Review

Gas turbine vendors and waste heat boiler vendors were contacted to obtain information on demonstrated performance and, where applicable, to obtain budget quotes for the cost of NOx emission control equipment. In addition, the USEPA BACT/LAER Data Base and the California BACT Data Bases were checked to confirm NOx levels that had been achieved on previous projects. The USEPA data base review concentrated on installations in colder parts of the U.S. as being more representative of Alberta operating conditions.

A capital cost, operating cost, and cost-effectiveness review ($/tonne NOx removed) was conducted. The technologies considered were: diffusion burners, dry low NOx burners (DLN), and SCR.

The emphasis on the technology review was gas turbines in the 20 to 85 MW range, although information was collected on units smaller than 20 MW and larger than 85 MW.

Vendor Supplied Information

The following vendors were contacted to obtain information on gas turbine systems in operation or being marketed in Alberta.

- GE
- Siemens
- Solar
- Mitsubishi – only markets turbines > 300 MW in Canada, so information on Mitsubishi turbines was not included in this study.
- Rolls-Royce – was contacted but did not provide information for the report.

The following table summarizes information supplied by the gas turbine vendors. In addition to the information shown in the table, the vendors provided information on the incremental cost of DLN burners versus diffusion burners, fuel firing rates, exhaust gas flow rates, and exhaust gas temperatures. This additional information was used during the evaluation of operating costs and cost effectiveness.

The NOx information in the Table B.1 is based on the use of “dry low NOx” (DLN) burners. GE provided information on their DLN1+ burner that is available on GE 7EA turbines, although not yet proven for operation in a cold climate. Siemens has a similar burner that has been available on their 113 MW SGT6-2000E turbine, but again has only been available in warm climates.

Because they are not proven in cold climates, these burners were not considered in this evaluation.

Table B.1 - Vendor Supplied Gas Turbine Information

GAS TURBINE VENDOR	MODEL	POWER OUTPUT, MW	EXHAUST NOx CONC, ppmvd	ALLOWABLE TEMP RANGE, ^{O}C	ALLOWABLE LOAD, %Full Load
GE	LM2500	22	25	-30 to +40	75 to 100
	LM6000	44	15	> -7	75 to 100
	Frame 6B	42	20	-43 to +39	70 to 100
	Frame 7EA	85	20 DLN	-43 to +39	70 to 100
	Frame 7FA	183	9	-30 to +40	52 to 100
Siemens	SGT400	13	15	-20 to +40	
	SGT600	25	25		80 to 100
	SGT700	31	15		70 to 100
	SGT800	47	15	-15 to +40	50 to 100
	SGT6-2000E	113	25		
	SGT6-5000F	206	9		60 to 100
Solar	Titan 130	14	25	> -18	50 to 100
			42	-30 to -18	50 to 100
			120	< -30	50 to 100
	Titan 250	22	25		

The following vendors were contacted to obtain information on Heat Recovery Steam Generators (HRSG). The vendors provided budget quotes for the incremental cost of adding SCR to HRSGs, including budget quotes for ammonia injection grids and ammonia vaporization systems. Budget quotes were provided for both 20 MW and 70 MW gas turbine systems, and for both supplemental fired and unfired systems. Both vendors have supplied HRSG and SCR systems for gas turbine installations in Alberta.

- Express Tech
- Deltak

The following vendors were contacted to obtain information on duct burner NOx generation options.

- Coen
- Hamworthy-Peabody

BACT/LAER Data Bases

The USEPA BACT/LAER Data Base and the California BACT Data Bases were checked to confirm NOx levels that had been achieved on previous projects. The USEPA data base review concentrated on installations in colder parts of the U.S. as being more representative of Alberta operating conditions.

The following table lists select installations that were included in the data bases. The USEPA RACT/BACT/LAER clearinghouse data was divided into gas turbine installations smaller than 25 MW and installations larger than 25 MW.

- For the most part the units smaller than 25 MW listed in the table were permitted for NOx levels in the 15 ppmvd to 25 ppmvd range. This NOx range corresponds to the vendor supplied information for gas turbines in this size range.
- The units smaller than 25 MW were selected because they were installed in colder climates. The units were also installed in areas that were attainment for NOx, so they were installed under BACT requirements not LAER requirements. SCR was not required for any of the installations listed.
- Three of the units larger than 25 MW that did not require SCR installations are included in the table. These installations all included gas turbines the vendors guaranteed for 9 ppmv NOx.

- Two of the units listed were described as having supplemental fired HRSGs plus SCR for NOx control. Supplemental firing can increase the NOx concentration by 30% to 60%, so if the gas turbine exhaust contained 20 ppmvd NOx, downstream of the duct burners the NOx would be in the 25 ppm to 30 ppm range. The units listed in the following table were permitted for 2.5 ppm to 3 ppm indicating an approximately 90% NOx reduction across the SCR.

The California BACT data base was reviewed because BACT in California requires the installation of the best demonstrated technology with no consideration for cost. This data base was reviewed to determine the lowest NOx demonstrated by gas turbine systems. All the units listed used SCR for NOx reduction. The units listed demonstrated that NOx levels as low as 2 ppmvd can be achieved using SCR.

In most cases the regulatory data bases provided information on whether the installations were simple cycle or combined cycle, so this information is included in the Table B.2. Neither the EPA nor California data bases included as a category so there is no information as to whether the installations were cogen systems or power plants.

Table B.2 - Gas Turbine Installations Accepted As BACT

DATA SOURCE	STATE	INSTALLATION	MW	NOx, ppmv @ 15% O2	COMMENTS
USEPA RACT/BACT/LAER Clearinghouse < 25 MW	Alaska	Phillips North Cook	5	31	Solar Tarus, simple cycle
	Alaska	Tesoro Kenai	8.3	130	Combined cycle
	Alaska	BP Badami	12	42	Solar Mars,
	Michigan	ANR Pipeline	10	22	Solar Mars
	Minnesota	CENEX	12	25	Combined cycle
	Nevada	Kern River Goodsprings	12	25	
	Wyoming	Kern River Trans	10	25	Simple cycle
	Wyoming	Williams Field	10	25	Solar Mars, combined cycle
	Wyoming	Williams Field	12	15	Solar Mars or Solar Titan, combined cycle
USEPA RACT/BACT/LAER Clearinghouse > 25 MW	Michigan	Detroit Edison	82	9	GE 7EA, simple cycle
	Minnesota	Great River Energy	109	9	Simple cycle
	Wisconsin	WE Energies	100	9	Combined cycle
	Wisconsin	WE Energies	180	3	GE 7FA with supplemental firing and SCR, combined cycle
	Wyoming	Black Hills Corp	40	2.5	Supplemental firing w SCR, combined cycle
California AQMD BACT Determinations Gas Turbines	California	Vernon City Power	43	2	535 MM btu/hr GT firing & 73 MM supplemental with SCR, combined cycle
	California	Indigo Energy	45	5	SCR, simple cycle
	California	El Colton LLC	48.7	3.5	GE LM 6000 with SCR, simple cycle
	California	Magnolia Power	181	2	GE 7FA with SCR 1700 MM btu/hr GT firing & 583 MM supplemental, combined cycle
					In California, BACT is best demonstrated technology without cost effectiveness consideration

Cost Effectiveness Evaluation

Vendor budget costs were obtained for the incremental cost of DLN burners versus diffusion burners and for the incremental cost of adding SCR to a HRSG. Vendor budget costs were obtained for both 20 MW and 70 MW gas turbine installations, and for supplemental fired and unfired systems. Total installed capital cost estimates were prepared for these four systems and extrapolated to estimate the costs for 42 MW and 85 MW systems. Operating costs and NOx reduction levels were estimated for all four sizes both with and without SCR.

For the cases with supplemental firing using duct burners, the economics and NOx emissions were based on two levels of supplemental firing:

- Firing the gas turbine exhaust to a temperature of 840^{o}C, and
- Firing the gas turbine exhaust to a temperature of 1070^{o}C.

<u>Cost Effectiveness Capital Cost and Annual Operating Cost Forms</u>

The USEPA provides standard spreadsheets for calculating "cost effectiveness". Jacobs uses these standard spreadsheets to conduct cost effectiveness reviews for projects all over the world, including World Bank projects in developing nations. While the forms are standard, the information provided in the forms is specific to each individual project.

Capital Cost Form:

- Vendors provided written budget quotes for the incremental cost of including an SCR system in a HRSG.
  - o The system cost included: the SCR catalyst, the SCR reactor housing, the ammonia injection grid, and the ammonia vaporization system.
  - o Jacobs added the cost of the ammonia storage system and the ammonia pumps.
  - o The budget quotes included the cost of providing HRSGs designed for a lower than normal pressure drop. Using this approach, the installation of an SCR would not increase the back pressure on the gas turbine, so we did not include a penalty for the loss in power output. The impact of SCR pressure drop was included in the capital cost instead of the operating cost.
- The standard spreadsheet is set up to estimate the cost of an installation on the U.S. Gulf Coast. A 1.5 location factor was used to correct for the cost of a project in Alberta versus the cost on the Gulf Coast. This multiplier was obtained from the Jacobs Cost Estimating Department, which reviews this value and updates it periodically.

- On past projects, Jacobs has learned that USEPA cost factors tend to underestimate the true capital cost. As part of an unrelated engineering project, Jacobs had recently estimated the cost of an SCR system for a cogen unit in Alberta and estimated a cost 29% higher than would be predicted using the USEPA factors. Therefore, an additional 1.29 adjustment factor was added to make the EPA method estimate more representative of actual costs.

- Estimates were prepared for the 70 MW systems, with and without duct burners following Jacobs estimating protocols. Equipment was sized, PFDs were prepared, and equipment and piping lists were prepared. The cost estimate for the 70 MW systems using Jacobs estimating protocols were within a few percent of the estimate using the above approach, verifying the accuracy of the above procedure for 70 MW installations.

Operating Cost Form:

- The USEPA's standard form was used to estimate the cost of operating labor, maintenance labor, and maintenance materials. SCR systems require very little operator and maintenance attention except to unload NH_3 once/week, or once every five to 15 years when the catalyst requires replacement. These costs are negligible in the overall cost effectiveness evaluation.

- NOx emission rates were calculated for each of the cases. These NOx emission rates were combined with estimates of NH_3 slip to calculate NH_3 consumption rates. A cost of $1000/tonne of pure ammonia ($5300/tonne of 19% aqueous solution) was used to calculate the NH_3 consumption cost. The $1000/tonne estimate came from recent reports on NH_3 costs in the Alberta area. The NH_3 consumption was calculated assuming 1.02 moles of NH_3 is required to reduce one mole of NOx, plus the NH_3 associated with 5 ppmvd NH_3 slip. Most of the NOx will be present as NO, which requires 1.0 moles of NH_3/mole NOx, but some of the NOx is present as NO2. NO2 takes more than one mole/mole, so the overall average is around 1.02 moles NH3/mole NOx removed.

- The 19% aqueous NH_3 consumption rate was used to calculate the energy required to vaporize the aqueous NH_3. The NH_3 is vaporized into an air stream that is below the temperature of the gas turbine exhaust gas and has a cooling effect on the exhaust gas. The cooling effect was calculated. The energy consumption used in the form is the sum of the energy needed to evaporate the NH_3 and the heat recovery lost because of cooling of the exhaust gas.

- The NH_3 consumption rate was used to estimate the electricity requirements for the blower that supplies air to the NH_3 vaporizer. Past Jacobs' data on blower power was extrapolated to the NH_3 consumption for each case.

- As mentioned above under capital cost estimating, no penalty was included for the impact of SCR pressure drop on the gas turbine power output. This penalty was applied to the capital cost instead of the operating cost. An alternate would have been to lower the capital cost and assume a loss in gas turbine output. Express Tech provided information that every unit they installed over 10 MW put extra area into HRSG to compensate for the pressure drop – none of the SCR installations resulted in an increase in back pressure on the gas turbine.

As a cross-check, both GE and Siemens provided information on the impact of pressure drop on turbine performance. Assuming 4" H_20 (10 mbar) pressure drop across the SCR, the vendors provided the following impact on gas turbine performance. This is a conservatively high pressure drop, past Jacobs installations have ranged from 2" to 4" pressure drop.

Loss in power output	0.42%
Increase in heat rate	0.42%
Increase in exhaust temperature	1.1^{o}C (increases heat recovery)
Overall impact on energy	0.45%

The impact on operating costs was calculated for the above conditions. The cost ranged from $90,000/year to $370,000/year depending on the unit size (8% to 15% of total annual cost). This high cost that would be associated with an increase in pressure drop confirms that it is more economical to put capital into pressure drop reduction, than to accept an increase in gas turbine back pressure.

- There are no contaminants in natural gas that poison SCR catalyst, but dust that passes through the gas turbine air filter can migrate into the pores, deactivating the catalyst. The catalyst life is expected to be 10 to 15 years, but Jacobs has only been able to obtain 5-year guarantees from vendors because long guarantees require the vendor to carry a liability on their accounting books. So the calculation of operating costs assumed the catalyst requires replacement every 5 years.
- The dominant operating cost is the "capital recovery cost". SCR systems are capital intensive, versus operating cost intensive. The Ontario guideline for BACTEA evaluations requires using the "long-term bond rate" to calculate the capital recovery cost. After some discussion about the appropriate long-term bond rate to use, CASA directed Jacobs to use 8%, along with a 15-year system life, to calculate the capital recovery factor.

Summary of BATEA Economic Analysis Form

The standard USEPA form was used to calculate the cost effectiveness of the different cases and different NOx control options.

- A Diffusion Burner was considered as base case for each evaluation. Most new installations utilize dry low NOx burners (DLN) but diffusion burners are required when burning high hydrogen fuels such as refinery fuel gas or syn gas because the flame flashes back into a DLN burner when hydrogen is burned. The potential also existed that combining a diffusion burner with an SCR may be more cost effective than providing a DLN burner.
- The NOx emissions from a diffusion burner were calculated based on the gas turbine vendor supplied exhaust gas rates and an assumed 175 ppmvd NOx in the gas turbine exhaust. The actual concentration varies from one gas turbine to another, and is a little lower during the winter than during the summer, but 175 ppmvd is a representative number.
- For the cases with supplemental firing, the assumed NOx generation rate was 38 g/GJ.
- The NOx emission rate calculated for the DLN burners was based on vendor supplied information. The exhaust gas NOx concentration is dependant on the gas turbine. The following gas turbines were used as the basis for the calculations:
    - GE LM2500 or Solar Titan for the 20 MW systems. The NOx emissions from these turbines were corrected for the higher NOx experienced during cold weather.
    - GE 6B and GE 7EA for the larger turbines. GE guarantees the NOx emissions for these units down to -43^{o}C, so no penalty was applied for cold temperature operation.
    - There are other turbines with lower summer NOx levels than the units assumed above, but that are more susceptible to cold temperatures. It was assumed that averaged over the year the NOx from these turbines would be similar to the NOx from the turbines listed above.
- The NOx emission rate assumed the units are operated at full load. This is a standard permitting approach to insure that unit throughput is not limited by the permit. The NOx emission rate also assumes the units are operated within their "allowable load" that forms a basis for the vendor guarantee. Cogen systems can experience significant swings in steam demand. Cogen systems that utilize supplemental firing in duct burners take these swings by controlling the supplemental firing rate, and combined cycle units take the swings by varying the steam extraction rate. But simple cycle systems with no duct firing have to throttle the gas turbine firing rate, which can increase the ppmv NOx and increase the g NOx/GJ.

- For the SCR cases, a 90% NOx reduction across the SCR was assumed.
  - o API 536 (Post Combustion NOx Control for Fired Equipment) states that "NOx reductions exceeding 90% are possible with an NH_3 slip of more than 5 ppmvd".
  - o In 2003 Jacobs installed SCRs on two GE 7EA gas turbines. Those SCRs were sized for a 95% NOx reduction, and met their guarantee.
  - o 43% more catalyst volume is required for a 90% NOx reduction than for an 80% NOx reduction but the cost of the catalyst is only a small part of the total capital cost, so the impact on capital cost is not large. There is no impact on operating or maintenance costs except for the higher cost each time the catalyst is replaced. The larger catalyst volume increases the generation of SO_3, but this is a negligible impact firing natural gas.
  - o The estimated NOx emissions assumed a 90% NOx removal over the life of the catalyst, and a 5 ppmvd NH_3 slip over the life of the catalyst. The catalyst has more activity when it is new, so is capable of > 90% NOx reduction. However, the standard approach is to throttle the NH_3 addition to hold the 90% NOx reduction. Using the standard control approach, the 90% NOx reduction is averaged over the life the catalyst, but the average NH_3 slip is less than 5 ppmvd. As the catalyst ages the NH_3 slip increases and the catalyst is replaced when the slip reaches the guarantee level.
- For the SCR cases, the Total Annualized cost was obtained from the Annual Operating Cost Form. Budget quotes were obtained from the vendors for the difference between DLN burners and diffusion burners. The capital recovery factor was used to convert those equipment costs to Total Annualized Costs. It was assumed the only cost impact was the cost of purchasing the gas turbine, and that there was no difference in installation costs.
- The cost effectiveness for the following cases were compared with the base case of a diffusion burner: DLN burner, diffusion burner + SCR, DLN burner + SCR.
- The incremental cost effectiveness for the SCR cases were compared with the DLN burner case.

Cost Effectiveness Results

Cost effectiveness is defined as the cost/tonne of emissions reductions. Cost effectiveness is calculated both compared to a base case and the incremental cost versus other cases. Cost effectiveness is calculated as the annualized cost/tonne of NOx reduction.

The results of the evaluation are shown in Tables B.3, B.4, and B.5 below.

Table B.3 lists the NOx emission levels for each of the turbine sizes and each of the NOx control options. The NOx concentration in the turbine exhaust is listed in ppmv, as quoted by the turbine vendors.

Table B.4 lists the estimated equivalent NOx emissions in units of grams NOx per gigajoule of total energy output. The total energy output is the sum of the power output and the energy content of the steam sent to cogeneration. NB: These are estimates only as the relationship between ppm NOx concentration and g/GJ is not the same for all turbines.

Table B.5 lists the calculated cost effectiveness of the various NOx control options, for each of the various cases. Cost effectiveness is calculated as the cost/tonne of NOx emissions reduction. The cost effectiveness of purchasing a gas turbine equipped with DLN burners instead of diffusion burners is shown. Also shown is the incremental cost, versus the DLN burner case, of a diffusion burner with SCR and a DLN burner with SCR.

Table B.3 – Estimated NOx Emissions for Alternate Cases

CASE	ESTMATED NOx EMISSIONS							
	Diffusion Burners		DLN Burners		Diffusion + SCR		DLN + SCR	
	ppmvd	t/yr**	ppmvd	t/yr	ppmvd	t/yr	ppmvd	t/yr
20 MW without Duct Burners	175	497	27*	79	18	50	3	8
42 MW without Duct Burners	175	1154	20	134	18	115	2	13
42 MW with Duct Burners fired to 840°C	186	1224	31	204	19	122	3	20
42 MW with Duct Burners fired to 1070°C	195	1284	40	264	20	128	4	26
70 MW without Duct Burners	175	1920	20	226	18	192	2	23
70 MW with Duct Burners fired to 840°C	186	2042	31	348	19	204	3	35
70 MW with Duct Burners fired to 1070°C	195	2143	40	449	20	214	4	45
85 MW without Duct Burners	175	2340	20	276	18	234	2	23
85 MW with Duct Burners fired to 840°C	186	2488	31	424	19	249	3	42
85 MW with Duct Burners fired to 1070°C	195	2610	40	546	20	261	4	55

- 20 ppmvd above -30°C and assumed 120 ppmvd below -30°C
- **t = tonne

Table B.4 – Estimated NOx Emissions for Alternate Cases With Unit Conversions

CASE	ESTMATED NOx EMISSIONS							
	Diffusion Burners		DLN Burners		Diffusion + SCR		DLN + SCR	
	ppmvd	g/GJ Energy Output	ppmvd	g/GJ Energy Output	ppmvd	g/GJ Energy Output	ppmvd	g/GJ Energy Output
20 MW without Duct Burners	175	390	27	60	18	39	3	6.0
42 MW without Duct Burners	175	390	20	46	18	39	2	4.6
42 MW with Duct Burners fired to 840°C	186	260	31	45	19	26	3	4.5
42 MW with Duct Burners fired to 1070°C	195	210	40	44	20	21	4	4.4
70 MW without Duct Burners	175	390	20	46	18	39	2	4.6
70 MW with Duct Burners fired to 840°C	186	260	31	45	19	26	3	4.5
70 MW with Duct Burners fired to 1070°C	195	210	40	44	20	21	4	4.4
85 MW without Duct Burners	175	390	20	46	18	39	2	4.6
85 MW with Duct Burners fired to 840°C	186	260	31	45	19	26	3	4.5
85 MW with Duct Burners fired to 1070°C	195	210	40	44	20	21	4	4.4

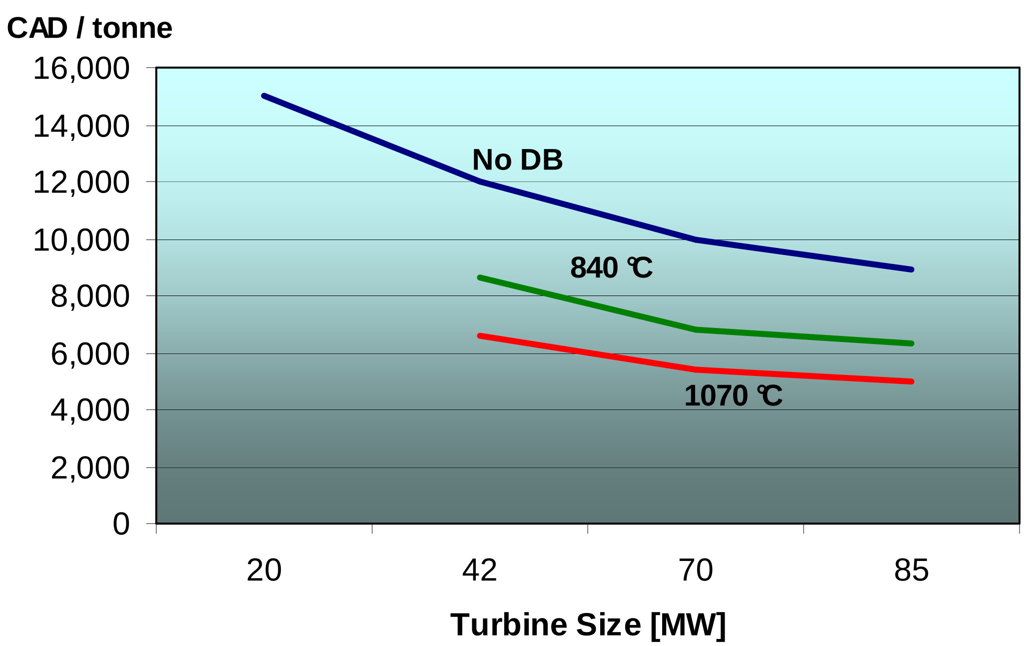
Table B.5 – Incremental Cost Effectiveness

CASE	INCREMENTAL COST EFFECTIVENESS, $/ Tonne NOx Reduction			
	Base Case Diffusion Burners	DLN Burners versus Diffusion	Incremental Cost Effectiveness vs. DLN Burner	
			Diffusion + SCR	DLN + SCR
20 MW without Duct Burners	-	140	25,000	15,000
42 MW without Duct Burners	-	80	74,000	12,000
42 MW with Duct Burners fired to 840°C	-	80	18,000	8,600
42 MW with Duct Burners fired to 1070°C	-	80	11,000	6,600
70 MW without Duct Burners	-	69	56,000	10,000
70 MW with Duct Burners fired to 840°C	-	69	14,000	6,800
70 MW with Duct Burners fired to 1070°C	-	69	8,800	5,400
85 MW without Duct Burners	-	57	51,000	8,900
85 MW with Duct Burners fired to 840°C	-	57	13,000	6,300
85 MW with Duct Burners fired to 1070°C	-	57	8,200	5,000

Figure B.1 shows the relationship between incremental cost effectiveness of applying SCR to DLN burner equipped turbines over the range of turbine sizes covered in this study. There are three curves on the plot: the blue line represents the case where there is no supplemental duct firing, the green line shows the case where there is supplemental firing to 840℃, and the red line shows the case where there is supplemental duct firing to 1070℃.

The curves show that SCR becomes more cost effective as the size of the turbines increases. This is because the NOx emissions increase linearly with size, but the cost increase is less than linear. An SCR is more cost effective where supplemental firing is being used because supplemental firing significantly increases NOx emissions but has only a small impact on the cost of an SCR system. NB: the curve should not be extrapolated above 85 MW – per data from both GE and Siemens, gas turbines larger than 85 MW have lower NOx concentrations than their 85 MW equivalents so adding an SCR to these larger units is less cost effective.

Figure B.1 – Incremental Cost Effectiveness of SCR over DLN Technology



Collateral Impacts

There is no collateral impact on the environment from using a DLN burner versus using a diffusion burner.

The collateral impacts of using an SCR for NOx control include: safety risk due to ammonia handling, the possibility of corrosion due to ammonia salts on heat recovery equipment, water consumption during the production of aqueous NH_3 solution, the disposal of SCR catalyst, and collateral emissions.

Safety concerns and the impact of ammonia salts on heat recovery are discussed in the SCR Risk Analysis section. The following table summarizes the water consumption and collateral emissions associated with the SCR. As can be seen by the table, water consumption and collateral emissions rates are small with exception of NH_3 slip.

- The water consumption was calculated based on the NH_3 consumption rate. The water rates listed in the table are the demineralized water required to dilute the ammonia to 19%. The water consumption is small on an annual basis, so more important is the number of truck loads to deliver the aqueous NH_3. The number of 23 m^3 trucks varies from one truck/6 weeks for the 20 MW case without duct burners to one truck/week for the 85 MW case with supplemental firing to 1070°C.

- The catalyst life is expected to be 10 to 15 years. This means that every 10 to 15 years the existing catalyst must be replaced and disposed of. The main active ingredient in the catalyst is vanadium. In the U.S. vanadium is not hazardous waste "toxicity characteristics list" so the spent catalyst is not considered a hazardous waste. The catalyst is typically disposed of by landfilling in an industrial landfill. The vanadium content of the catalyst could be recovered but this is not economical and is typically not done. The quantity of catalyst required for a GE 7EA gas turbine SCR is around 200 tonnes. If the life of the catalyst is 10 years, on the average approximately 20 tonnes would be sent to a landfill each year.

- The calculated NH_3 emissions slip to the air. Ammonia is an alkaline compound that is naturally occurring in nature, but can react with SO_3 in the air to form PM2.5. In parts of the U.S. that are attainment for ozone but non-attainment for PM, the regulators put more emphasis on NH3 emissions than on NOx emissions. In the table the NH_3 slip is shown two ways:

    - As tonnes/year of NH3 emissions

    - As tonnes/year of PM2.5 assuming all the NH_3 reacts with SO_3 in the air to form a particulate. This is a conservatively high number because some of the NH_3 will be scrubbed from the air by rainfall, and thus not all the NH_3 will end up as a particulate.

- The three columns to the right contain an estimate of the emissions that would be measured in the discharge stack. On past Jacobs' projects, these numbers have been used for permitting purposes.

- PM2.5 forms when NH_3 reacts with SO_3. With 5 ppmv NH_3 slip the SO_3 concentration in the stack is limiting so the PM2.5 calculation assumes all the SO_3 reacts to form ammonium bi-sulfate (ABS). The calculation is based on the assumption that 5% of the SO_2 is naturally converted to SO_3 during combustion and that an additional 3% of the SO_2 converts to SO_3across the SCR catalyst – the SCR catalyst is an oxidizing catalyst that converts part of the SO_2 to SO_3.

- Part of the SO_2 in the flue gas oxidizes to SO_3 during combustion. If there is no SCR this SO_3 emits to the atmosphere as H_2SO_4. The ammonia added to the SCR system reacts with the SO_3 preventing the formation of H_2SO_4 thus reducing H_2SO_4 emissions.

- The heat required to vaporize the NH_3 and the steam generation lost because of the cooling effect of the injected NH_3/air is small. The CO_2 was calculated based on the extra boiler firing required to make up the steam requirement, assuming a boiler efficiency of 80%. The extra CO_2 emitted is a small number. This number is based on the assumption that capital is spent to avoid increasing the back pressure on the gas turbine, which is the economical approach for a new installation. An alternate calculation was made assuming a 4" H_2O increase in gas turbine back pressure – for the largest system in the table the increase in CO_2 emissions would be 2000 tonne/year.

- **Table B.6 –** Collateral Impact of SCR

CASE	WATER IN 19% NH_3, m^3/Year	COLLATERAL EMISSIONS				
		NH_3 Slip(1)		Emissions Measured in Stack, tonne/yr		
		NH_3, tonne/yr	Equiv ABS, tonne/yr	PM2.5(2)	H_2SO_4(2)	CO_2
20 MW without Duct Burners	160	6.1	41	0.058	(0.031)	50
42 MW without Duct Burners	290	12	81	0.13	(0.073)	90
42 MW with Duct Burners fired to 840°C	400	12	81	0.14	(0.073)	120
42 MW with Duct Burners fired to 1070°C	510	12	81	0.14	(0.073)	150
70 MW without Duct Burners	470	22	149	0.23	(0.12)	140
70 MW with Duct Burners fired to 840°C	690	22	149	0.23	(0.12)	210
70 MW with Duct Burners fired to 1070°C	830	22	149	0.23	(0.12)	250
85 MW without Duct Burners	580	25	169	0.28	(0.15)	170
85 MW with Duct Burners fired to 840°C	430	25	169	0.28	(0.15)	250
85 MW with Duct Burners fired to 1070°C	1050	25	169	0.28	(0.15)	320

Notes:

(1) Assumed 5 ppmv NH_3 slip over the life of the catalyst. Annual average slips are lower – the NH_3 slip is low when the catalyst is fresh and increases to 5 ppmv at the end of the catalyst life.

(2) Emissions based on natural gas containing 4 ppmv total sulfur. For a refinery process gas containing 100 ppmv total sulfur, emissions would be approximately 25 times higher than shown in the table. The calculated PM2.5 assumes the NH_3 added to the SCR precipitates all the SO_3 as ammonium bi-sulfate (ABS). The NH_3 converts H_2SO_4 to ABS thus reducing the H_2SO_4 that would form from combustion if there is no SCR.

SCR RISK ANALYSIS

There are two risk areas associated with the use of SCR for NOx reduction:

1. Ammonia handling safety concerns
2. Maintenance concerns because of the generation of ammonium sulfate salts that can precipitate, fouling heat transfer systems.

Ammonia Safety

Ammonia is an irritant that can damage the eyes, nose, and throat and, with severe exposure, can also be fatal. However, there are a large number of SCR systems in operation that safely handle NH_3. Plus, NH_3 is safely handled in agriculture where it is used as a fertilizer.

Critical NH_3 safety limits are:

- Upper explosive limit 28%
- Lower explosive limit 15%
- NIOSH recommended exposure limit
    - Eight hour exposure limit (TWA) 25 ppm
    - Immediately Dangerous to Life and Health (IDLH) 300 ppm

<u>Commercial Forms of Ammonia</u>

There are three forms of commercially available NH_3

- Anhydrous (100%) liquid NH_3: this is the cheapest form of NH_3 but because it is a pressurized liquid it is the most hazardous. In the U.S. anhydrous NH_3 is regulated by both the USOSHA and the USEPA.

- 29% aqueous ammonia: ammonia dissolved in demineralized water. This form of NH_3 is less hazardous to handle than anhydrous. In the U.S. this form of NH_3 is exempt from USOSHA requirements but is still regulated by the USEPA. The USEPA requires incident modeling and the reporting of any potential release scenarios that could result in high concentrations of NH_3 outside the facility boundary.
- 19% aqueous ammonia: which is the least hazardous of the three forms, but is the most expensive because of the cost of transporting water. 19% aqueous is exempt from both USOSHA and USEPA requirements. This is the most common form of NH3 used in SCR facilities designed by Jacobs. Per contacts with HRSG vendors, this is the most common form of NH_3 used in SCR systems in Alberta.

19% aqueous NH_3 freezes at – 33^oC. Freeze protection is required in Alberta but the freezing point is low enough that freeze protection is manageable.

Aqueous Ammonia Safety

While 19% aqueous **NH_3** is less hazardous than the other forms, precautions are required to both prevent fires and explosions and to prevent exposure to toxic concentrations. The vapor space over a 19% aqueous solution at 20^oC contains 22 vol% NH_3. This is within the explosive range and exceeds the short term allowable exposure limits.

Standard SCR system designs incorporate a number of safety features to protect against fires and explosions:

- The ammonia is typically vaporized into an air stream, then injected upstream of the SCR. The air stream is sized to keep the NH_3 concentration below the lower explosive limit, and multiple interlocks are used to prevent concentrations in the flammable range.

- Even though the probability of a fire or explosion is very low, the area around the NH_3 storage and vaporization systems has an electrical classification compatible with NH_3.

Jacobs conducted dispersion modeling to evaluate the impact of a potential NH_3 storage tank rupture at one facility. Toxic concentrations of NH_3, greater than 300 ppm, were found to exist up to 150 meters downstream of the storage facility. While this is a very low probability occurrence, it was modeled for planning purposes.

Impact of Ammonium Sulfate Salts on System Performance

Any excess ammonia added to SCR systems can impact cogeneration system maintenance in two ways:

- Decreased corrosion from condensation of sulfuric acid on downstream heat transfer surfaces

- Increased maintenance from fouling of downstream heat transfer surfaces with ammonium sulfate salts.

Decreased Corrosion from Sulfuric Acid Condensation

Part of the sulfur in the fuel converts to SO_3 during combustion. When the flue gas is cooled, the SO_3 reacts with moisture in the flue gas and condenses as sulfuric acid. Firing fuel gas containing 100 ppmv total sulfur, the sulfuric acid dew point is around 106^oC in gas turbine exhaust. To prevent corrosion the tube wall temperature is typically kept higher than 106^oC to prevent corrosion.

The addition of NH_3 reduces concerns from H_2SO_4 corrosion. The NH_3 ties up the SO_3 so it can not form sulfuric acid. NH_3 is also an alkali that neutralizes acid – NH_3 is added to the overhead of distillation towers to reduce corrosion. ABS deposits are mildly corrosive, so NH_3 reduces but does not totally eliminate corrosion.

Jacobs installed an SCR on an existing refinery heater that was experiencing sulfuric acid corrosion of the air preheater. The NH_3 slip from the SCR neutralized the sulfuric acid and essentially eliminated the corrosion problem.

Ammonium Sulfate Fouling of Downstream Heat Recovery Surfaces

Heat recovery is frequently used downstream of an SCR. The potential exists, and frequently is a reality, that the ammonium bisulfate (ABS), or ammonium sulfate, will precipitate on the heat transfer surface. If the tube walls are below the dew point temperature, the ABS will precipitate on the tubes. If the bulk gas temperature drops below the dew point, the ABS will precipitate as fine particles in the flue gas.

The deposits are highly conductive, so heat transfer loss has not been a concern. But pressure drop increase has been a problem for some installations.

Dew Point of Ammonium Salts

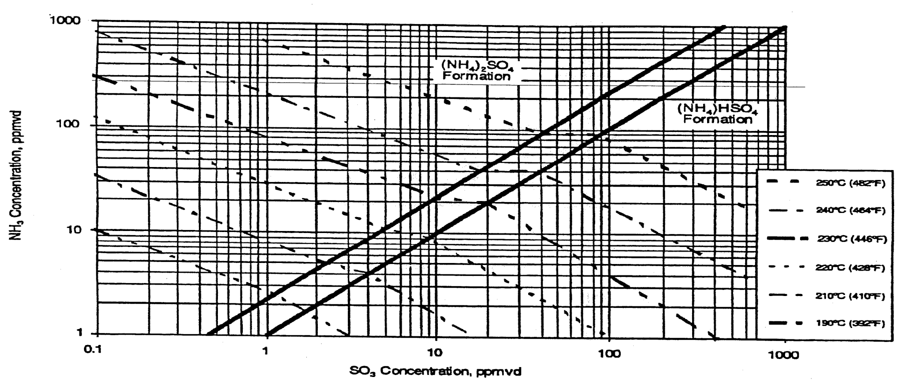
The temperature at which the ammonium sulfate salts start precipitating (dew point) is a function of both the ammonia and the SO_3 concentration.

The figure below is taken from API 536, Figure 6. This figure can be used to determine the dew point of the mixtures in and out of the SCR. Some SO_3 is formed naturally during combustion, but additional SO_2 is converted to SO_3 across an SCR. Depending on the temperature and catalyst composition, between 1% and 5% of the SO_2 is converted to SO_3 across the SCR.

Note: the following curve is based on 10% water in the flue gas. Limited data from one vendor indicates the dew point increases approximately 7°C for each 10% increase in the water concentration (10% water increase to 20% water).

Ammonium bisulfate $(NH_4)\ HSO_4$ condenses as a liquid, which then freezes at a temperature slightly below the condensing temperature. Ammonium sulfate de-sublimes as a solid and thus is not as sticky. The figure below shows which form should precipitate, based on laboratory experiments. However, the ammonium bisulfate reaction is fast and the ammonium sulfate reaction is slow, so in practice the stickier ammonium bisulfate is almost always the predominant species.

Figure B.2 – API 536 Figure 6 – Ammonium Salt Dew Point, 10% Water



Heat Transfer Surface Fouling

The EPA did research on the impact of ABS on heat recovery systems. This data is reported in EPA-600/7-82-025a (April 1982). This research resulted in a correlation that predicts when fouling problems will and will not occur. The EPA research resulted in the following correlation:

Deposition Number = [NH_3] X [SO_3] X [T_{ABS} – T_{rep}]

[ ] is concentration, ppmv

T_{ABS} = ABS dew point temperature, ^oC

$T_{rep} = (0.7)(T_{cold\text{-}end}) + (0.3)(T_{exit\text{-}gas})$

$T_{cold\text{-}end}$ = tubewall temperature at cold end of unit, ^oC

Deposition numbers. The EPA recommended deposition numbers are:

- < 10,000 correspond to units with very little operating problems
- >30,000 are units that have had severe problems.

The Deposition Number is negligible firing natural gas. The following is an example of a Deposition Number firing refinery fuel gas containing 100 ppmv total sulfur.

- SO_2 in flue gas = 3.4 ppmvd
  - Assume 5% of the SO_2 converts to SO_3 during combustion = 0.17 ppmvd
  - Assume 3% of SO_2 is converted to SO_3 in SCR = 0.10 ppmvd
  - Total SO3 = 0.27 ppmvd
- Assume 5 ppmvd NH_3 slip
- ABS Dew Point for 0.27 ppmvd SO_3 and 5 ppmvd NH_3 = 197^oC
- Assume $T_{cold\text{-}end}$ = tubewall temperature at cold end of unit = 106 ^oC, to be conservative
- Assume $T_{exit\text{-}gas}$ = 250^oC

T_{rep} = (0.7 X 106) + (0.3 X 250) = 149^oC
Dep # = [5] X [0.27] X [197 – 149] = 65 << 10,000 where ABS fouling reported

Per the deposition number, fouling of an economizer downstream of an SCR should not be a concern. To date, Jacobs has not experienced fouling of economizers in applications firing refinery fuel gas or natural gas.

Analysis of Incremental Control Cost on a Per Unit Commodity Basis

To better understand the effect on overall economics, the control costs are considered on a *"per unit of commodity generated"* basis. The situations considered for generating commodities at the HRSG, and the assumptions to calculate amount of commodity generated, are:

1. **Combined Cycle** – The steam generated at the HRSG drives a steam turbine to generate additional electricity. The flue gas stack temperature is assumed to be 100℃ (see section D), and the efficiency of converting the heat recovered at the HRSG to the electricity generated at the steam turbine, is assumed to be 50%.
2. **SAGD** – Steam is generated in a once-through steam generator. The flue gas stack temperature is assumed to be 215℃ (see section D). The boiler feedwater temperature is assumed to be 200℃, and the steam raising press ure 11200 KPag.
3. **General Steam Raising** – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, for a boiler fe edwater temperature of 100℃. To cover the wide range of steam generation pressures and degrees of superheat, different scenarios are considered across the pressure range 350 to 11200 KPag and the temperature range from saturated steam to superheated at 500℃.

Each situation was simulated to calculate the amount of commodity generated. From these, a Factor is calculated representing the amount of commodity generated per unit of heat recovered in the HRSG. The table below presents the results:

Table B.7 – Generated Commodity Factors

	Typical BFW Temp	Flue Gas Stack Temp	Commodity Factor (factor on heat output at HRSG)
Combined Cycle	40℃	100℃	**$MW_{electricity}$** = 0.5/3.6 x GJ/h
SAGD - OTSG	200℃	215℃	**kg/h Dry Steam** = 488 x GJ/h
Steam Raising - General	100℃	115℃	**kg/h Dry Steam** (range) = 330 to 440 x GJ/h

This factor is used to calculate the amount of commodity generated for each case in the cost effectiveness tables. The incremental cost of control is then calculated on a per commodity basis, to allow comparison of control technologies across the gas turbine size ranges.

Where steam is generated in the SAGD and Steam Raising situations the control cost is allocated in part to each commodity by the ratio of the fuels fired at the gas turbine and HRSG. For example, if 70% of the fuel is fired in the gas turbine, then 70% of the control cost is assigned to the electricity generated at the gas turbine. The remaining 30% of the control cost is assigned to the steam generated in the HRSG.

The results are presented in the graphs below. For General Steam Raising (as described in the Table above) two cases are considered: the minimum steam generation (at 330 kg/ GJ/h), and the maximum steam generation (at 440 kg/ GJ/h).

Figure B.3 - Combined Cycle Control Costs for 1070°C Duct Firing

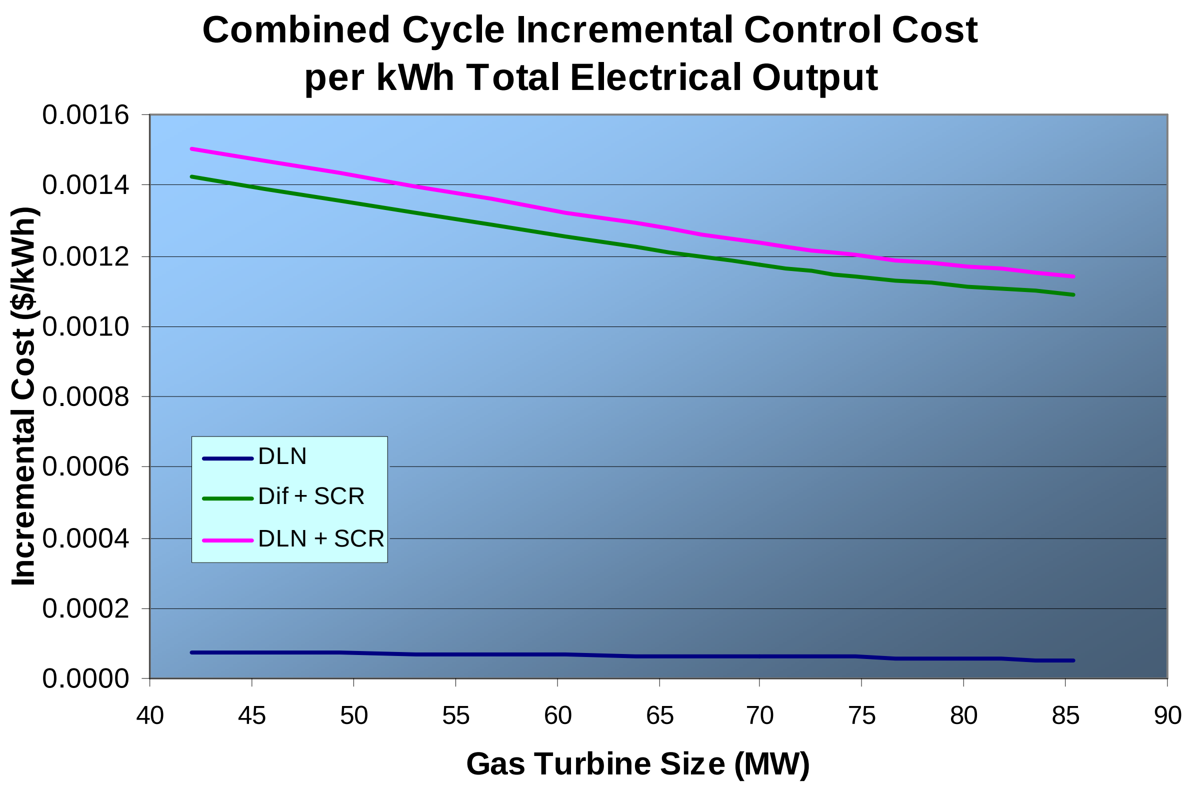
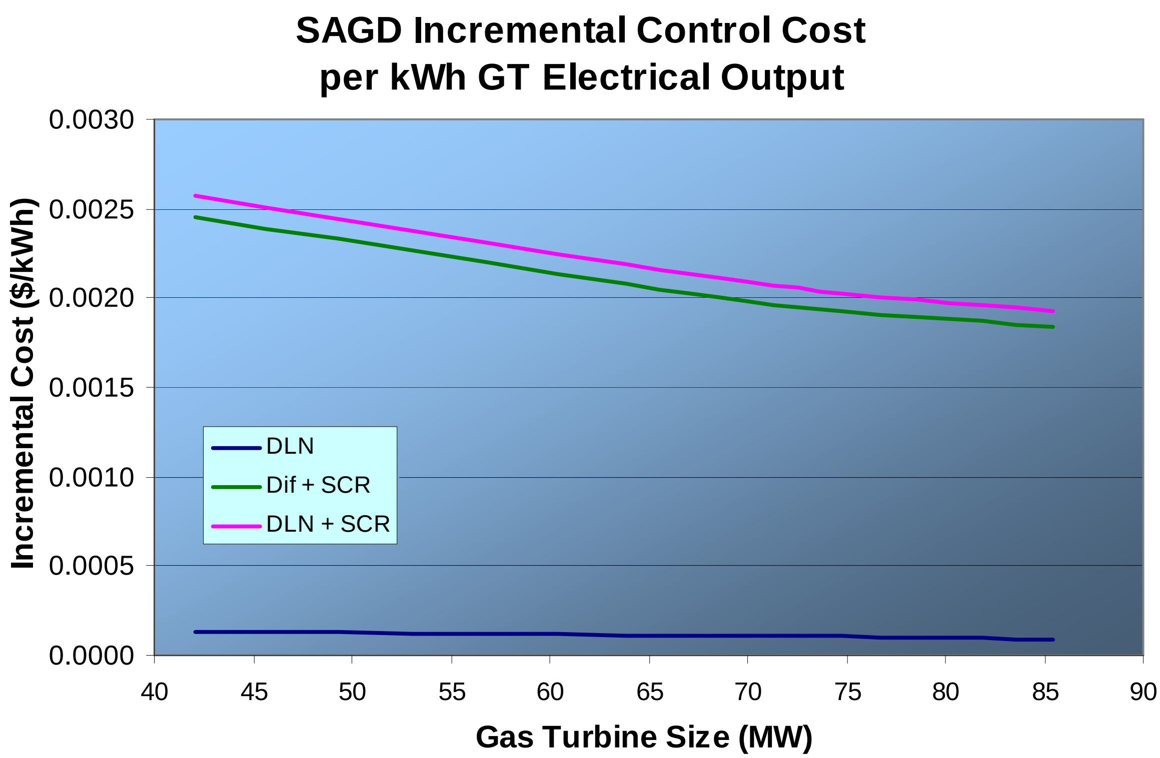


Figure B.4 - SAGD Control Costs for 1070℃ Duct Fir ing



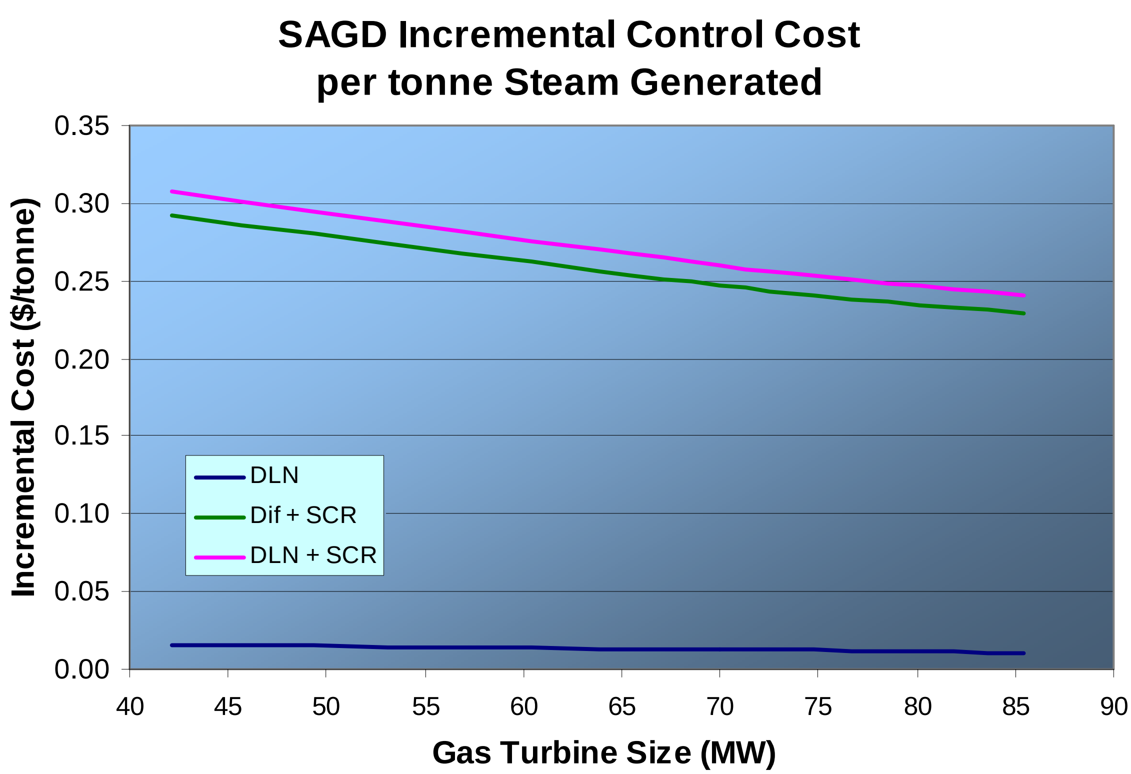
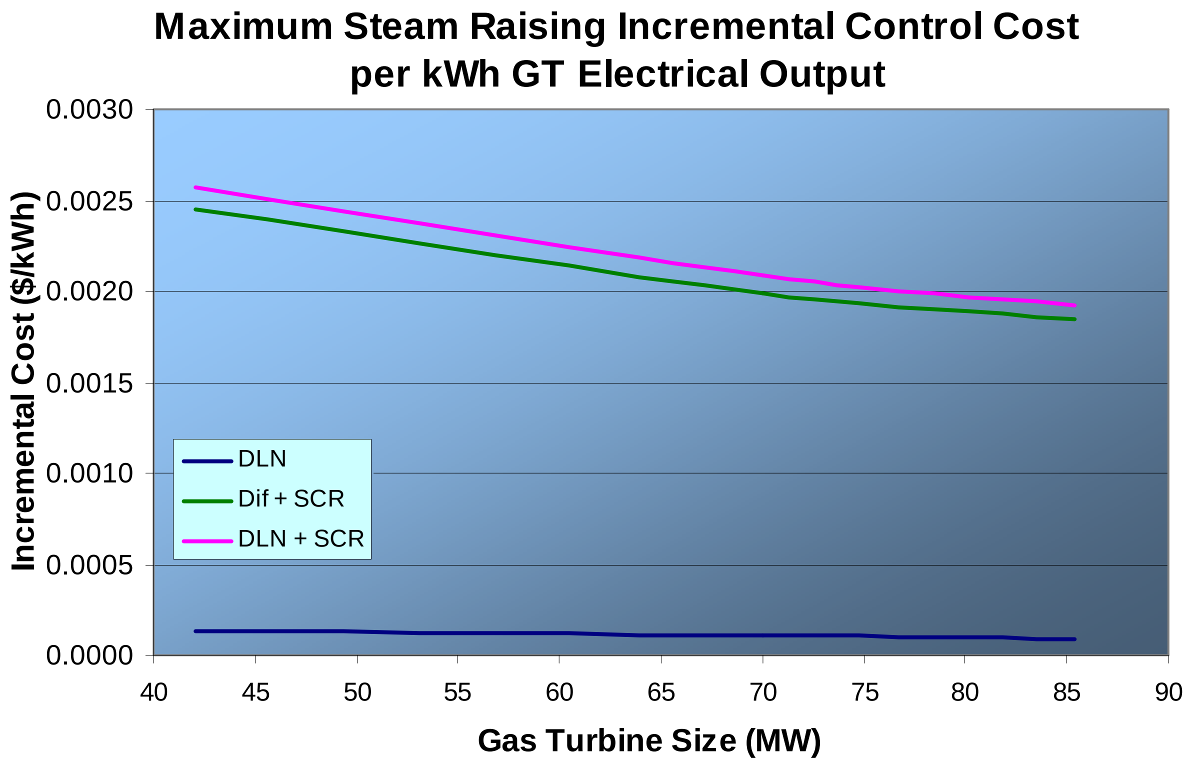


Figure B.5 - Maximum (440 kg/ GJ/h) Steam Raising, Control Costs for 1070℃ Duct Firing



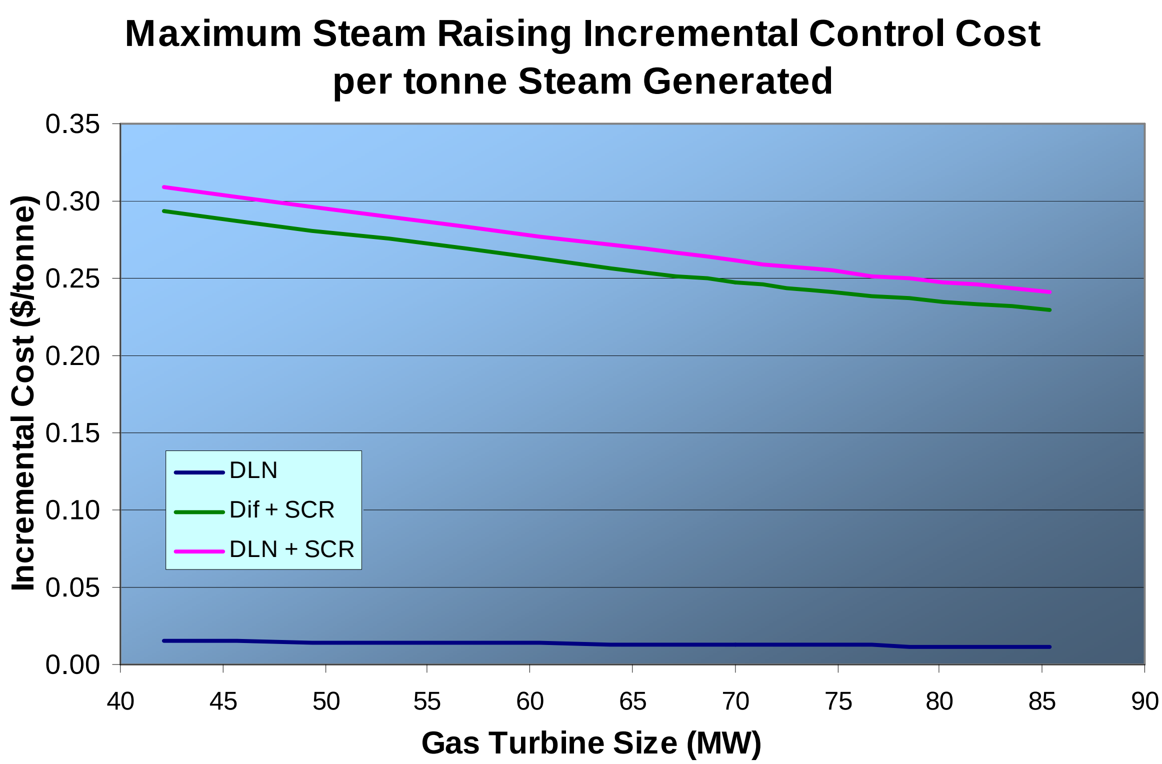
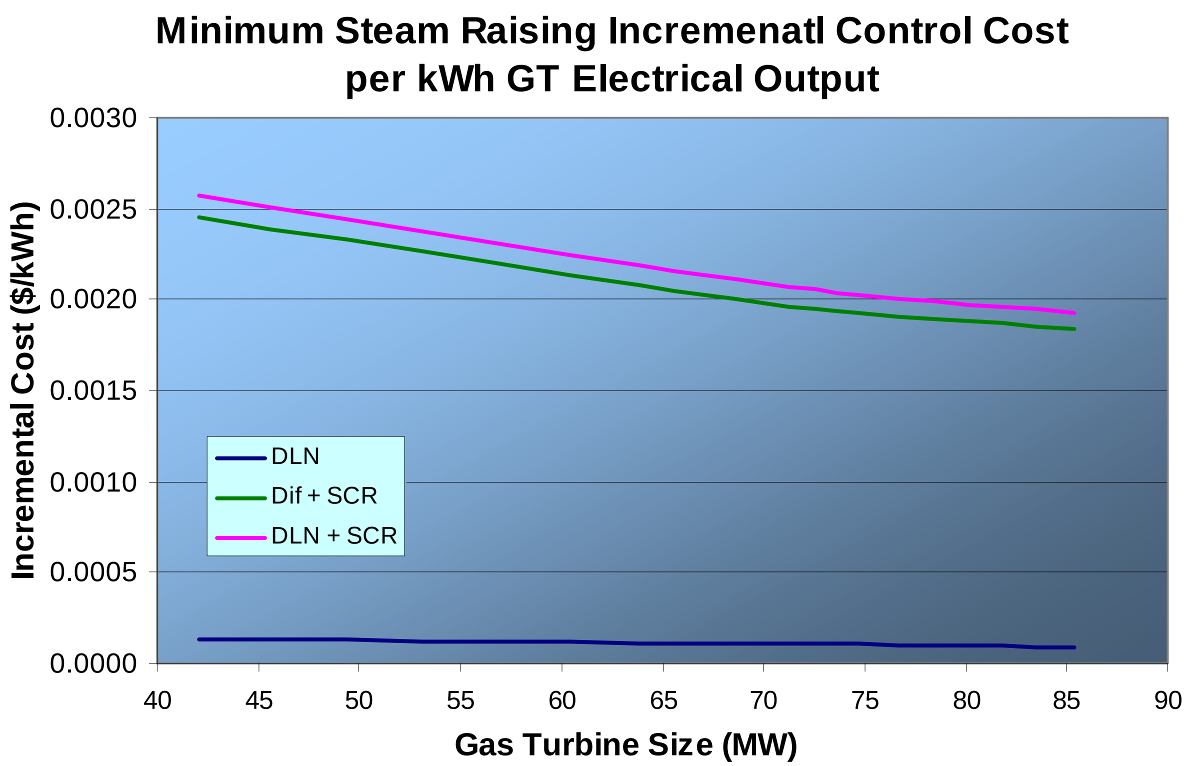


Figure B.6 - Minimum (330 kg/ GJ/h) Steam Raising, Control Costs for 1070℃ Duct Firing



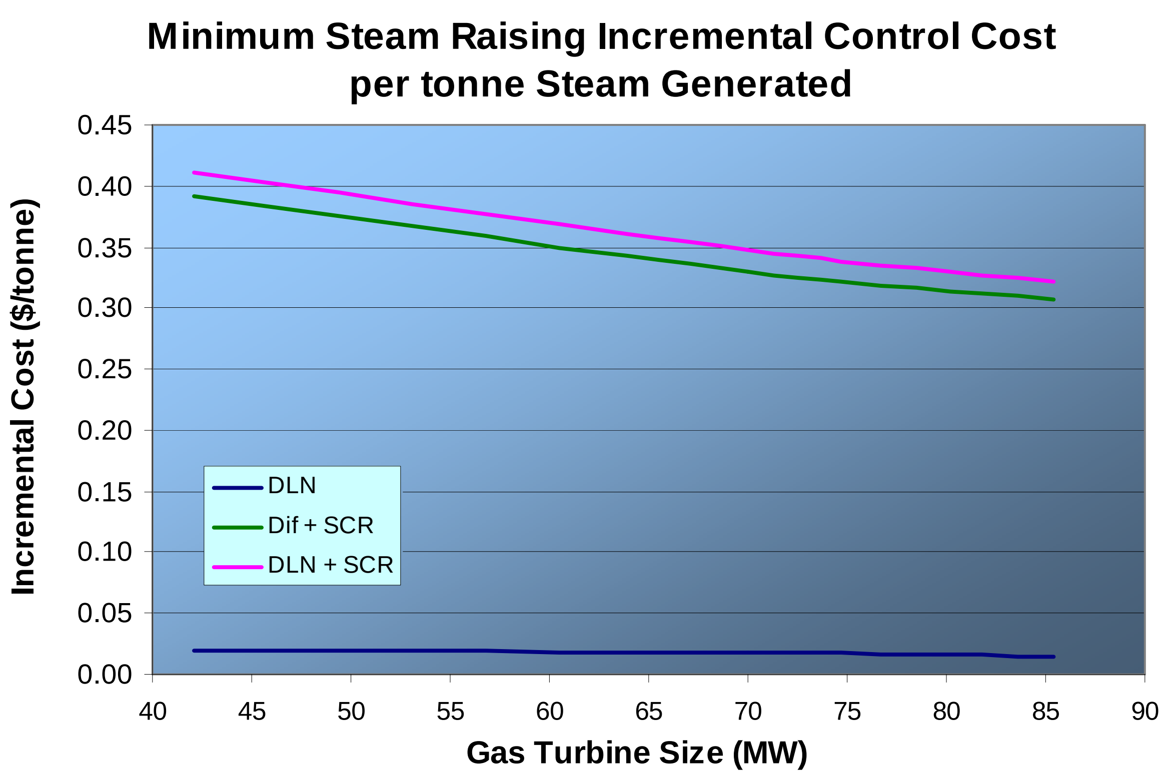


Figure B.7 - Combined Cycle Control Costs for 840℃ Duct Firing

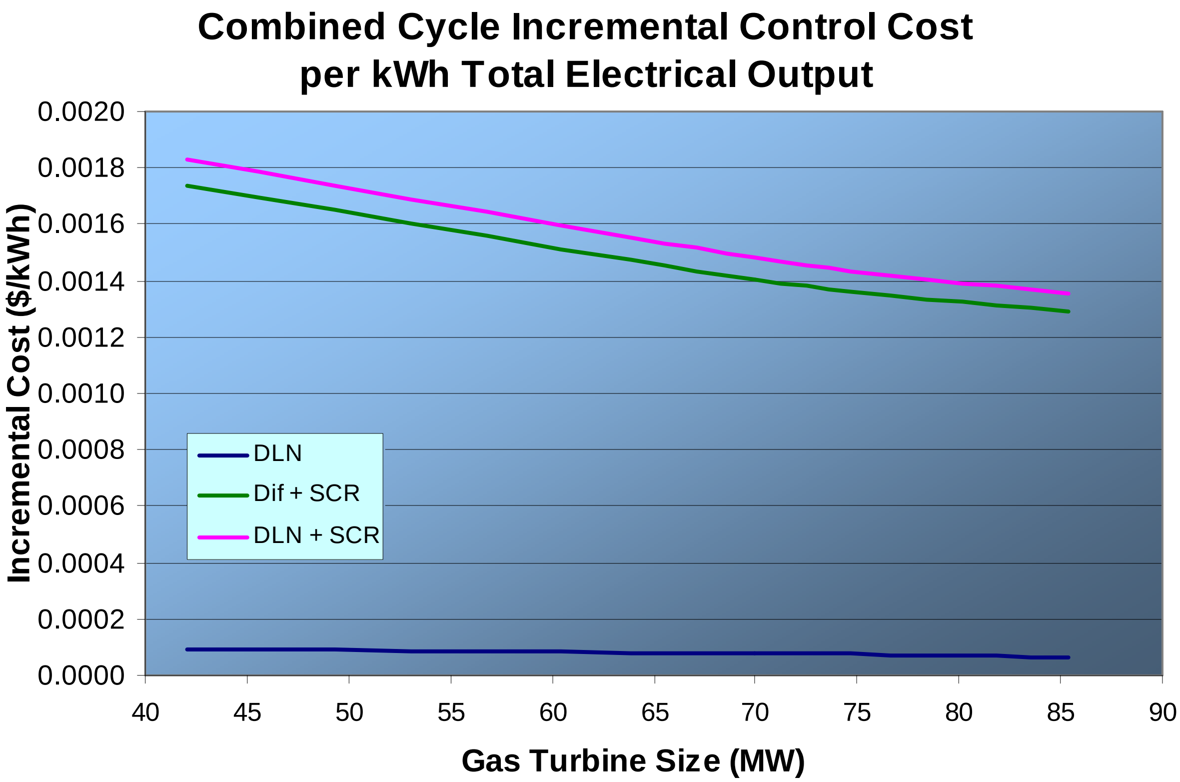
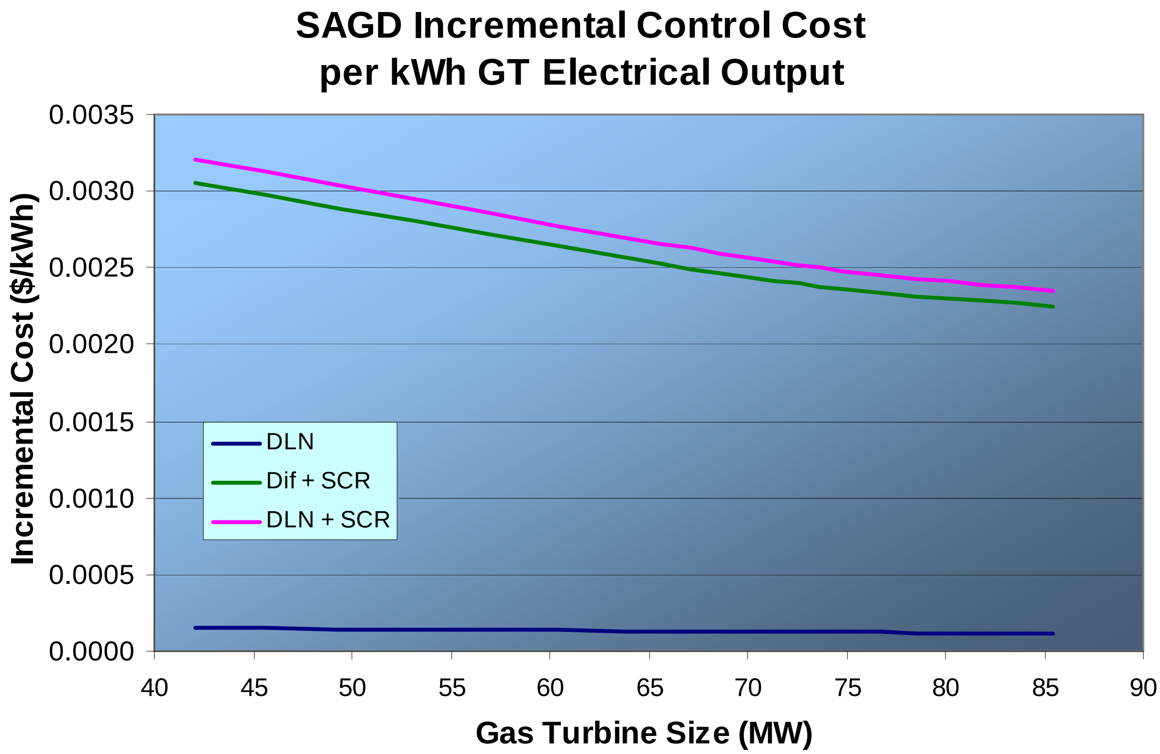


Figure B.8 - SAGD Control Costs for 840℃ Duct Firi ng



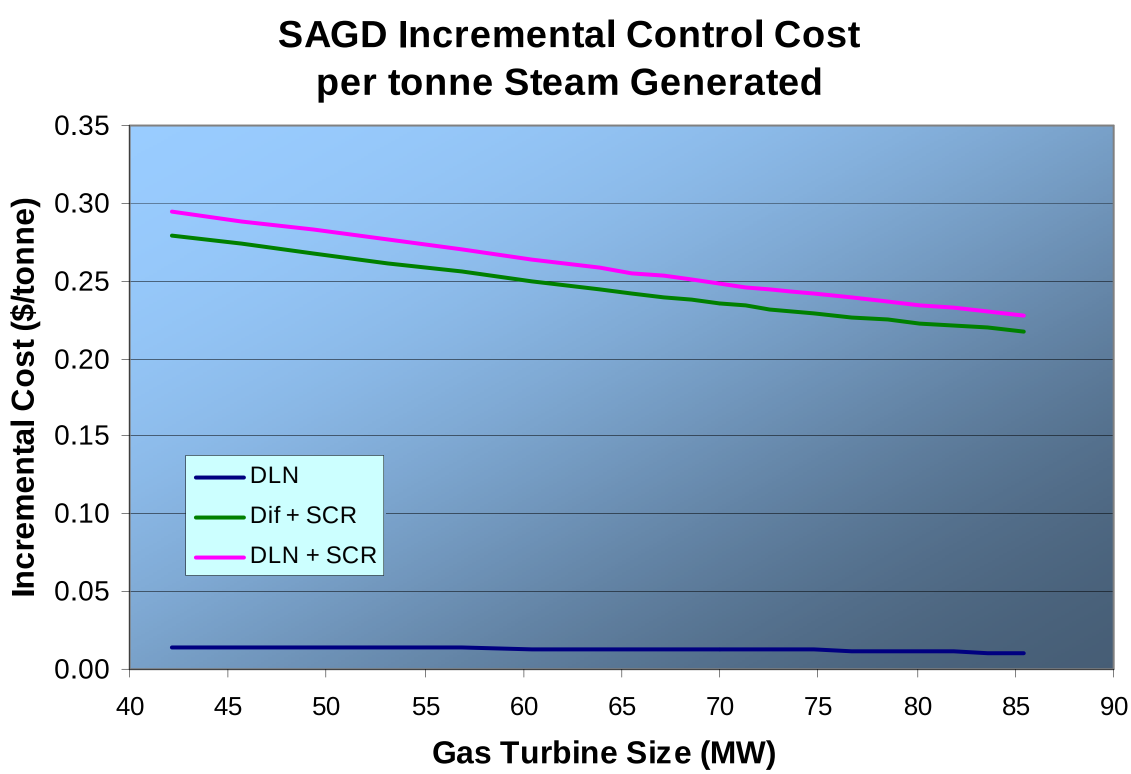
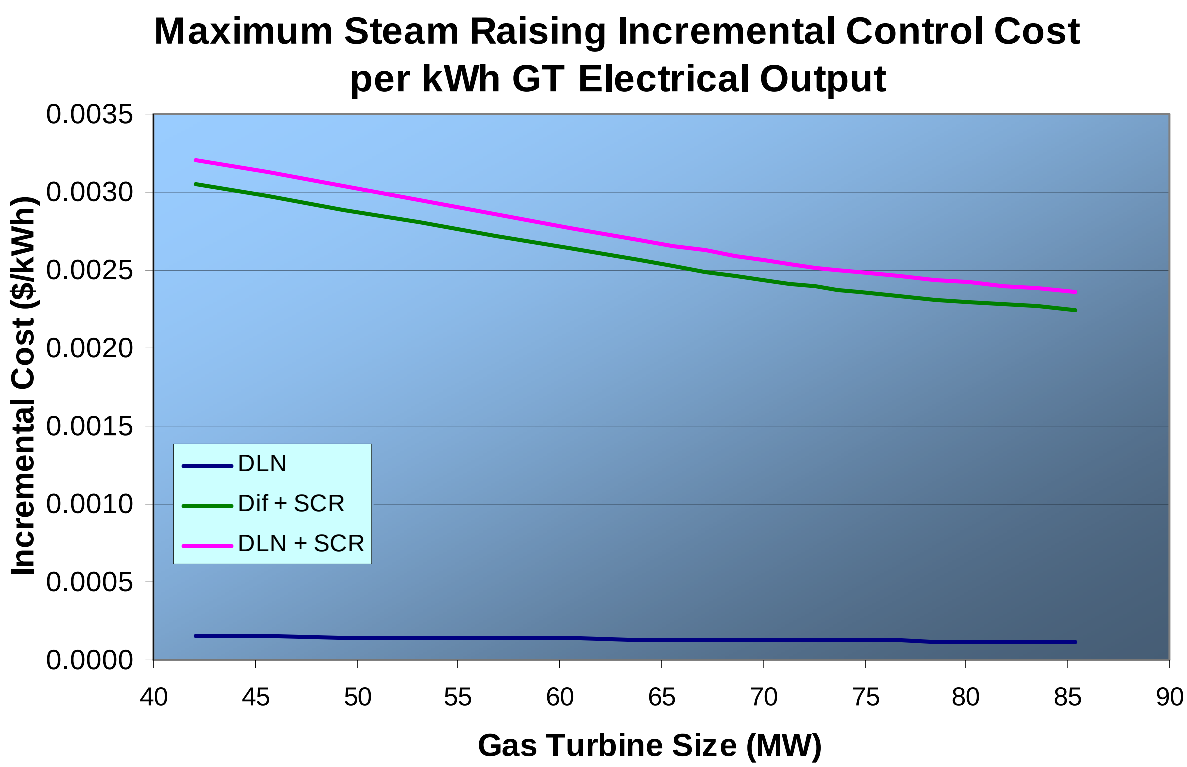


Figure B.9 - Maximum (440 kg/ GJ/h) Steam Raising, Control Costs for 840℃ Duct Firing



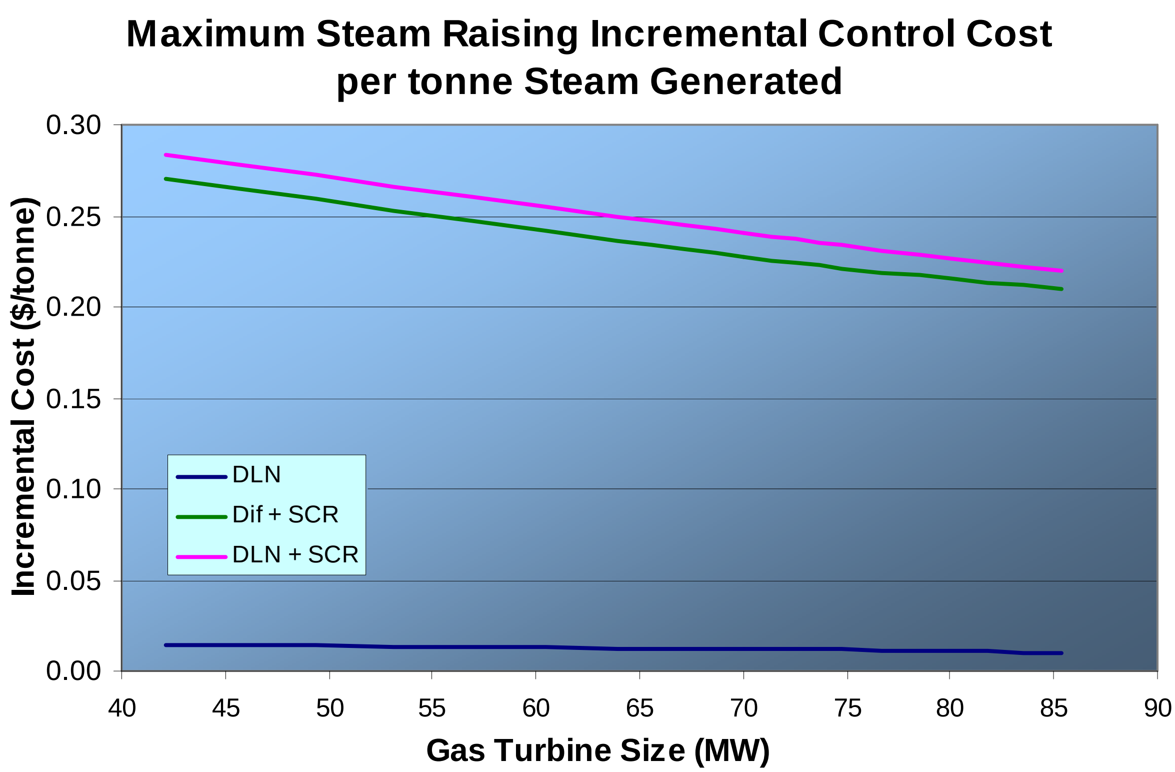
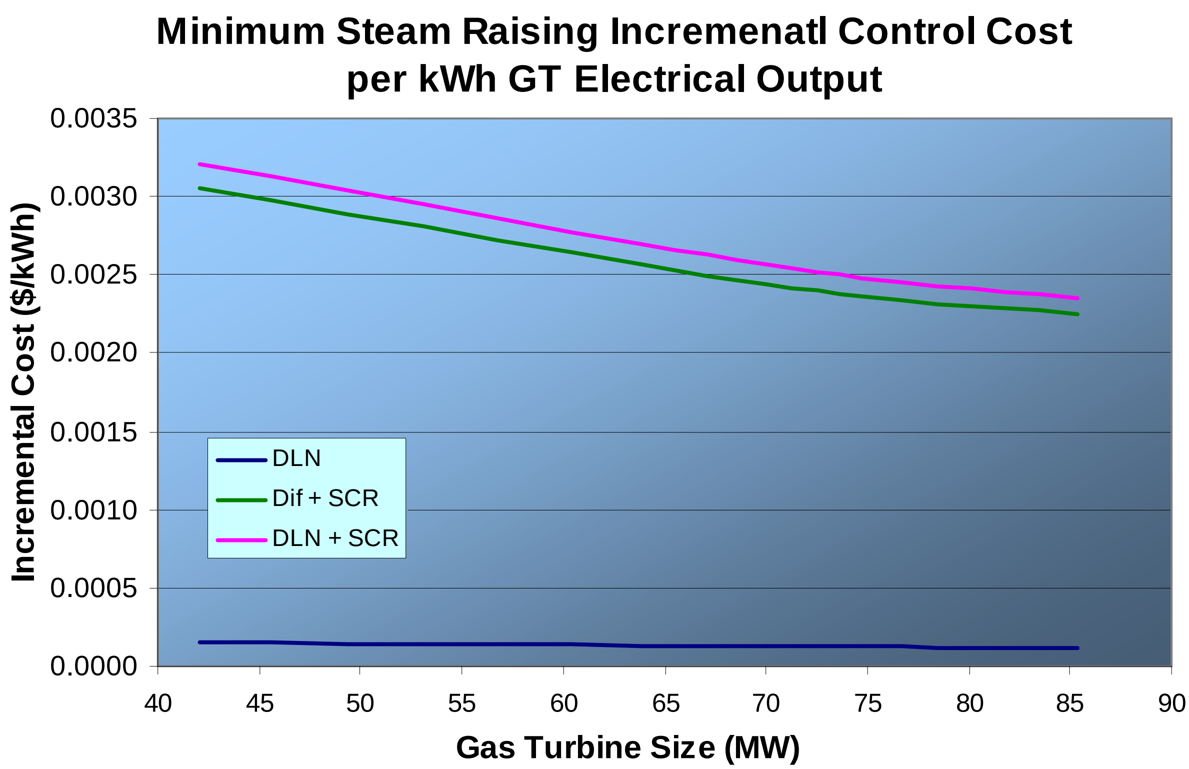


Figure B.10 - Minimum (330 kg/ GJ/h) Steam Raising, Control Costs for 840℃ Duct Firing



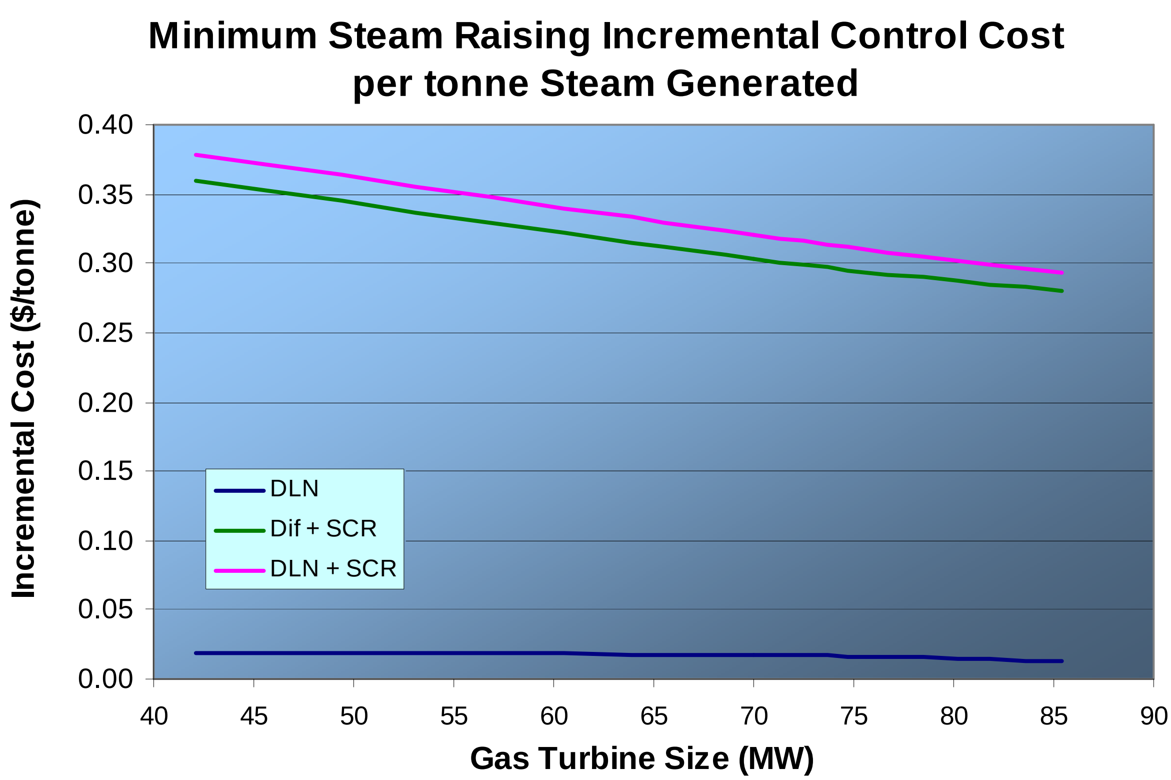


Figure B.11 - Combined Cycle Control Costs for No Duct Firing

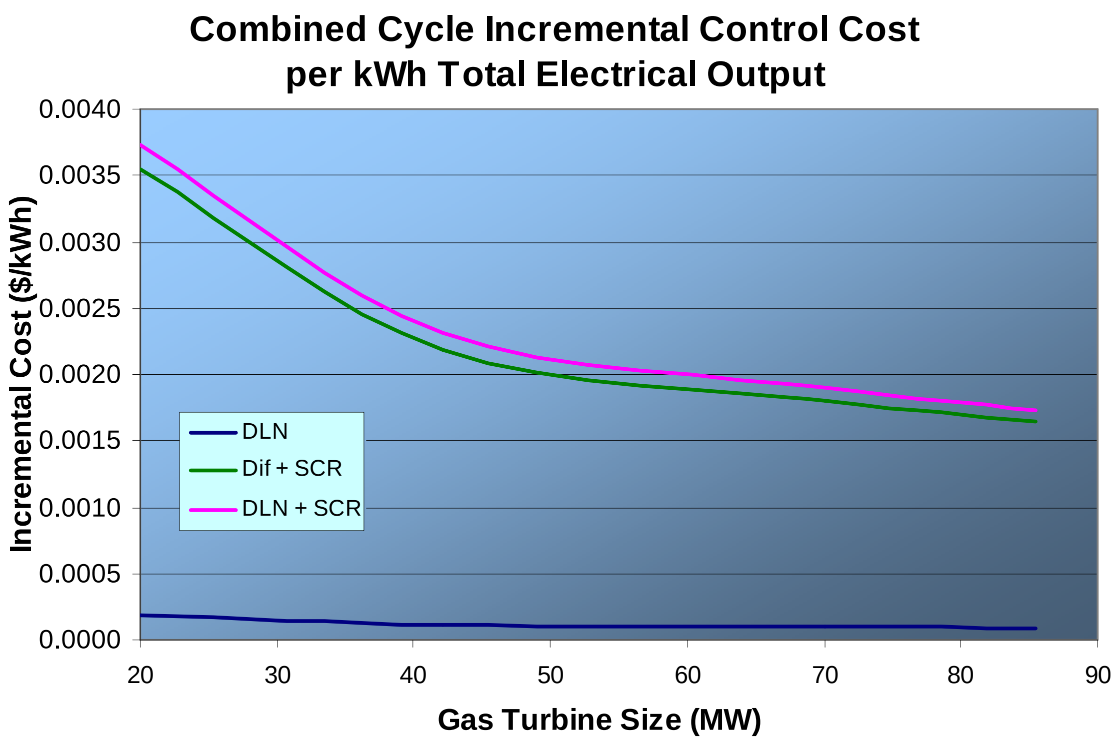


Figure B.12 - SAGD Control Costs for No Duct Firing

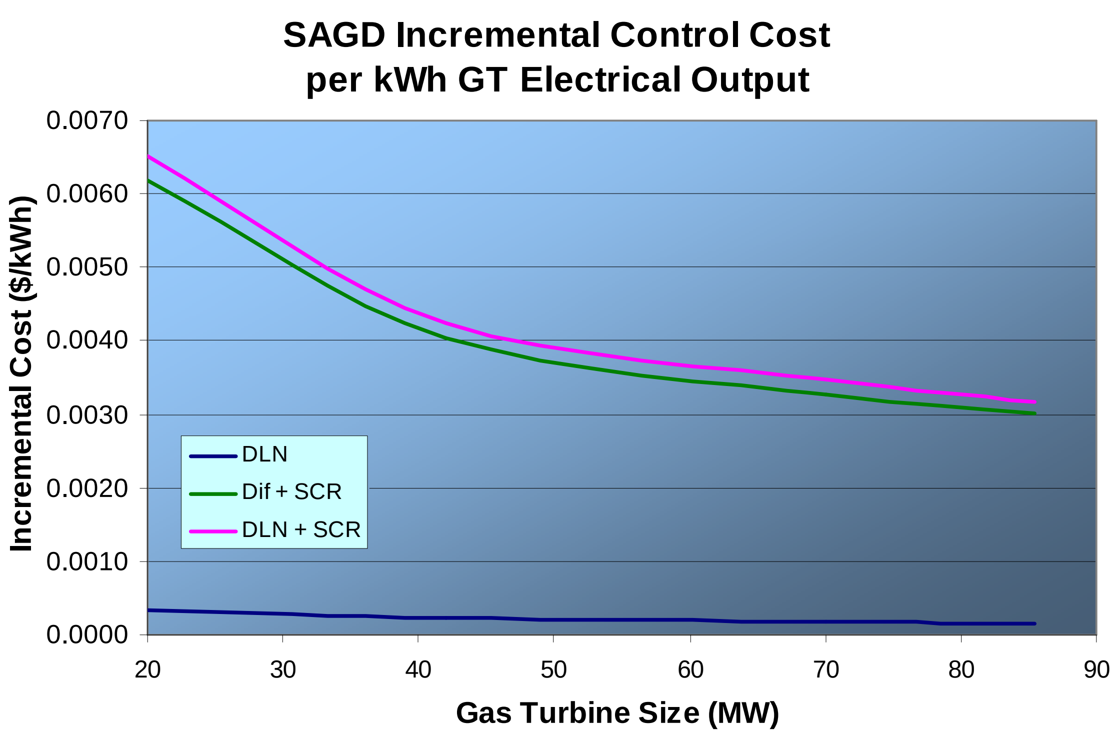


Figure B.13 - Maximum (440 kg/ GJ/h) Steam Raising, Control Costs for No Duct Firing

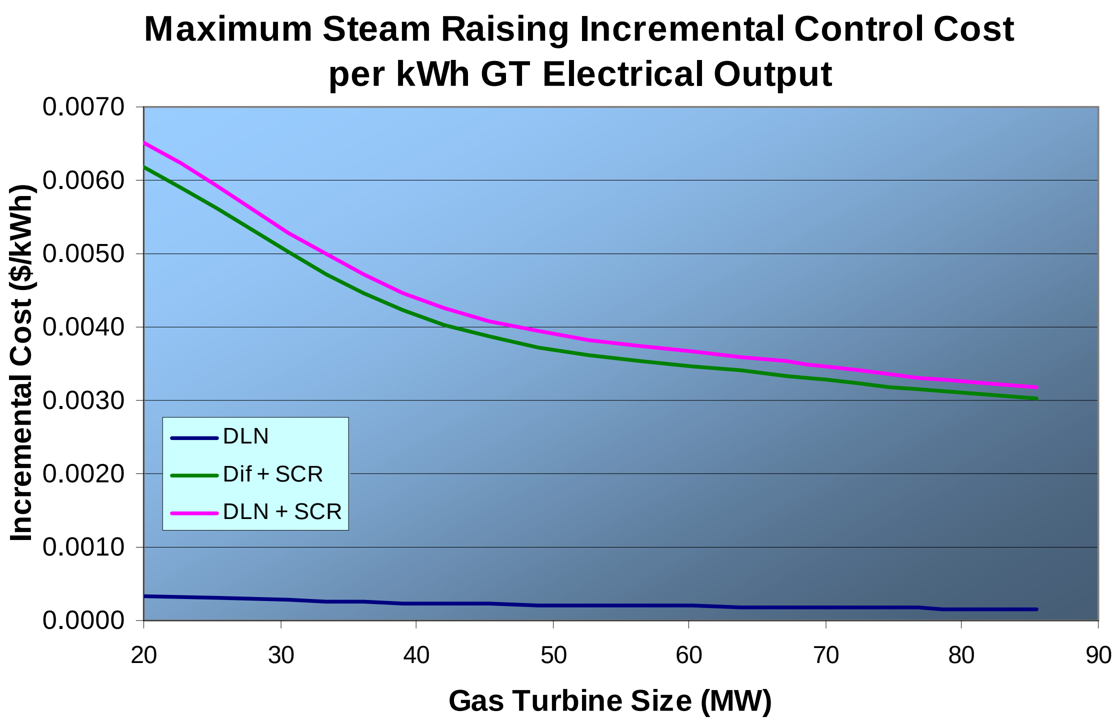
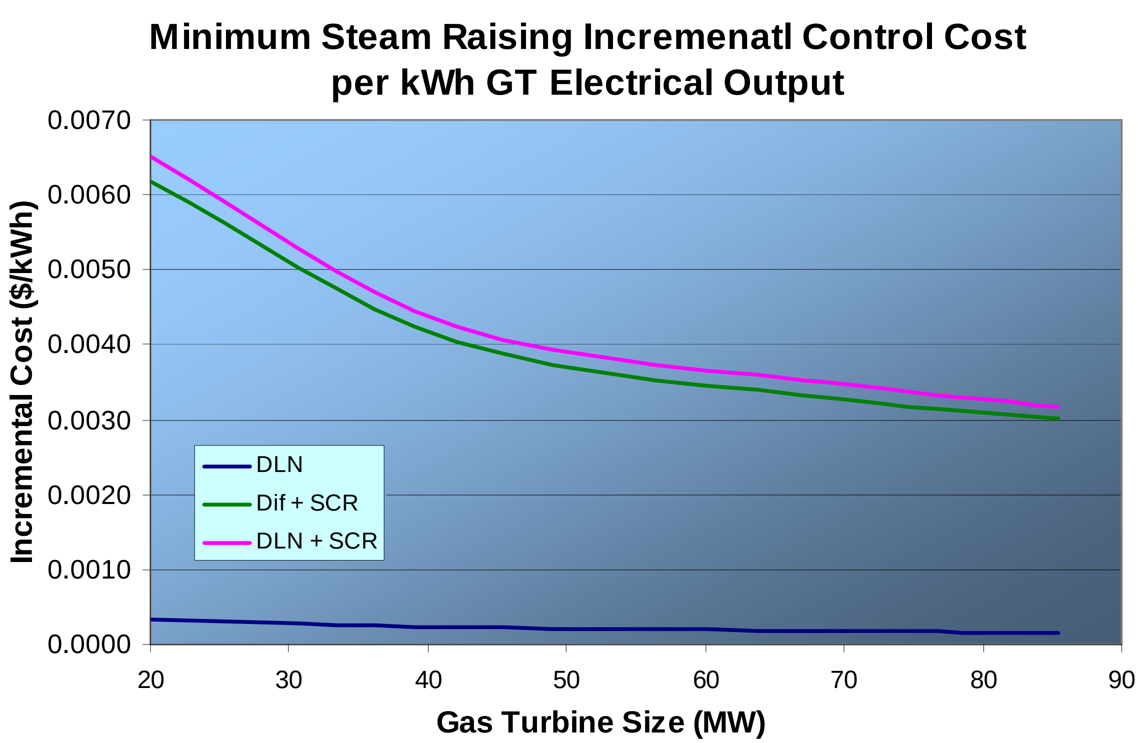


Figure B.14 - Minimum (330 kg/ GJ/h) Steam Raising, Control Costs for No Duct Firing



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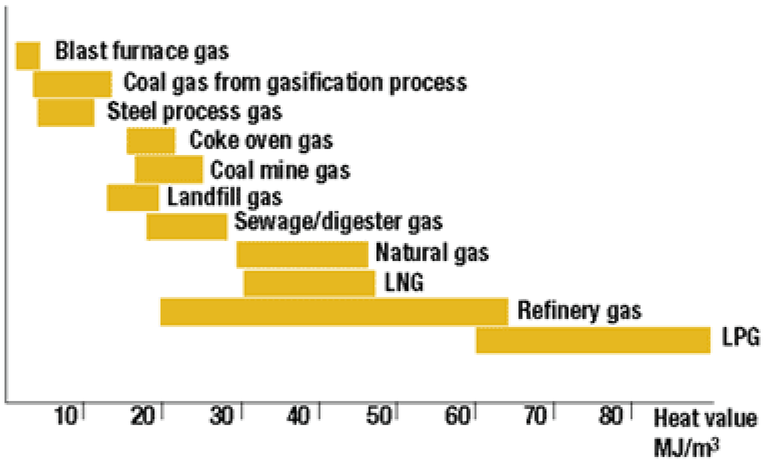
Section C.

Alternate Fuels

Background

Gas turbines have, over the years, demonstrated the capability to accept a wide variety of fuels. Figure C.1 shows the diversity of fuels that have been used[1].

Figure C.1 – Gas Turbine Fuels



Reference: McMillan, Robin and Marriott, David, "Fuel-Flexible Gas-Turbine Cogeneration", Siemens AG, 2008

Fuel Properties and Combustion

However, turbines must be engineered for the specific fuel to be used; any particular machine can tolerate only limited variation in fuel properties. When considering combustion technology, the important properties are specific heat content, flame velocity and flammability limits.

Heat Content
The heat content determines the volume which must be fired for a given power output. Figure C.1 indicates a difference of over 800% between the highest and the lowest heat contents of possible fuels. Consequently, the volume handling capacities of the fuel systems for turbines at either end of the range would differ by a similar amount.

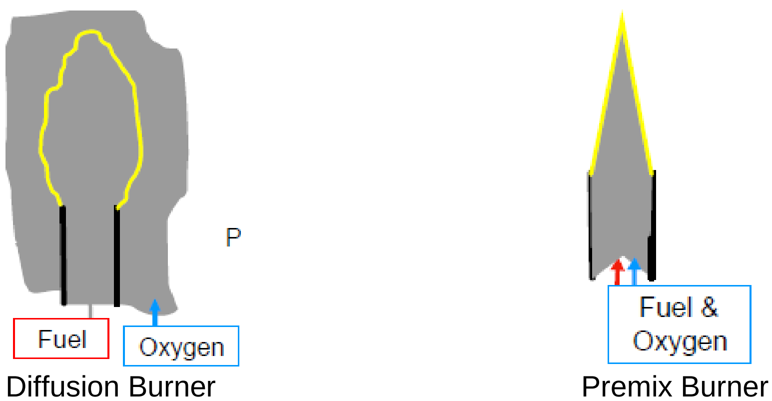
Flame Velocity
The flame velocity of a fuel affects the choice of combustion technology that will be used. For natural gas fired turbines the technology has evolved from diffusion burners to staged combustion burners. In diffusion burners, the fuel and the air enter the combustor at different locations and the rate of mixing determines the location of the flame front.

As manufacturers began looking for ways to reduce NOx emissions, the combustor designs were changed to include the injection of water or steam into the combustion zone. This cooled the flame to temperatures where less NOx formation was formed but, while effective, added extra cost to the system because of the extra equipment and the need for water treatment.

A later step in the evolution of the combustion technology came with the concept of premixing the fuel with excess air before it enters the combustion zone. The extra air serves to cool the flame without the need for injected water and decreases the residence time associated with the formation of the flame. As NOx formation increases with temperature and with time spent at high temperature, both of these features serve to reduce the NOx created. The flame front in this type of burner is determined by the flame velocity relative to the rate of fuel/air injection. This has implications for the suitability of this technology for fuel gas alternatives to natural gas.

The sketches in Figure C.2 represent the conceptual difference between diffusion and premix burners.

Figure C.2 – Diffusion and Premix Burners



In Alberta, two natural gas alternatives that are sometimes considered are syngas and refinery fuel gas. Syngas, a combustible mixture of hydrogen and carbon monoxide, is created in the gasification process, which is getting more consideration due to the desire to reduce carbon dioxide emissions to the atmosphere. Gasification provides a route to recover byproduct carbon dioxide at high pressure making it more suitable for capture than in conventional combustion processes.

Firing of syngas fuels with compositions of up to 100% hydrogen(2) while achieving low NOx emissions(3) has been demonstrated under test conditions, however, massive injection of diluent is required and would not currently be feasible for commercial applications.

Even for commercial applications, diluent is still required. Commonly used diluents are steam, nitrogen and carbon dioxide with the choice based on availability and cost at the user's facility(4). Gas turbine vendor guarantees in the range of 20 to 30 ppm NOx can be obtained but values are highly dependent on the gas composition and the diluent being used.

Refinery fuel gas is mixture of the byproduct offgases created by the thermal cracking and hydroprocessing units typically found in refineries or heavy oil upgraders. One trait shared by refinery fuel gas and syngas share is the presence of hydrogen.

The hydrogen concentration in a turbine fuel is important because it has a higher flame velocity than methane. As a result, firing high hydrogen content fuel in a burner utilizing premixed fuel injectors (e.g. a low NOx burner) will result create a situation where the flame front will establish itself too close to the injector, a potentially damaging condition referred to as flashback. Although some authors have suggested that this problem can be solved through the injection of massive quantities of steam or nitrogen diluent(5), it is not recommended by turbine manufacturers(6). Therefore, standard practice is to fire hydrogen containing fuels in diffusion burners and control the NOx emissions through the use of water or steam injection in the combustion zone or flue gas clean-up via SCR.

Figure C.3 is a photograph showing damage to a burner caused by flashback(7).

Figure C.3 – Burner Damage Caused by Flashback

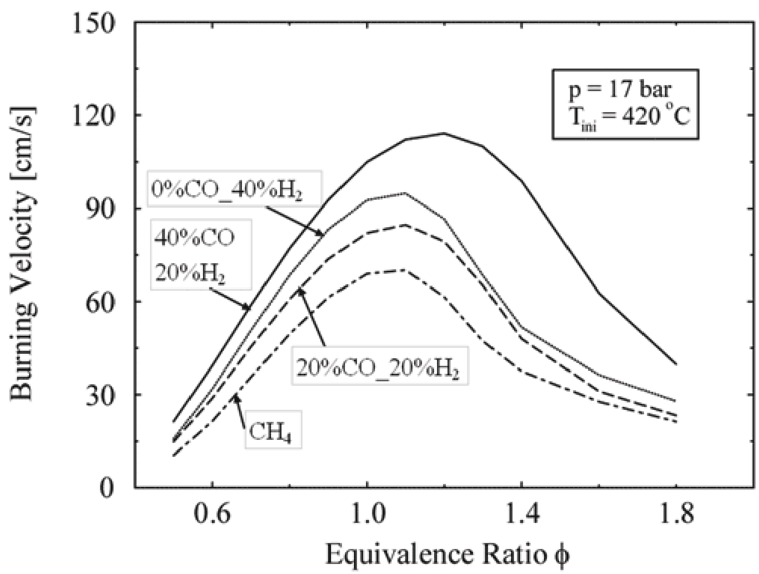
The graph in Figure C.4 below shows how the flame velocity in a fuel mixture is influenced by the fuel composition across a range of equivalence ratios where,

Equivalence Ratio, Φ = the actual air:fuel ratio / the air:fuel ratio required for complete combustion.

The graph shows that the flame velocity changes significantly between the case where natural gas is being fired (the bottom curve) versus the case where the hydrogen content is increased to 40% (the third curve from the bottom). In the results shown, the remainder of the fuel gas is nitrogen.

Note also how an increase in carbon monoxide level from 20% (second curve from the bottom) to 40% (top curve) causes the flame velocity to increase even as the hydrogen content is held constant.

Figure C.4 – Influence of Fuel Composition on Flame Velocity



Reference: McMillan, Robin and Marriott, David, "Fuel-Flexible Gas-Turbine Cogeneration", Siemens AG, 2008

A further indication of the specificity of gas turbine fuel requirements is given in Table C.1 below, which excerpted from GE's fuel gas specification[(8)]. Note that the maximum acceptable concentrations for each of hydrogen and carbon monoxide are listed as "trace".

Table C.1 – Example Fuel Specification for Industrial Gas Turbines

FUEL PROPERTIES	MAX	MIN	NOTES
Gas Fuel Pressure	Varies with unit and combustor type	Varies with unit and combustor type	See note 3
Gas Fuel Temperature, °F	see note 4	Varies with gas pressure	See note 4
Lower Heating Value, Btu/scft	None	100-300	See note 5
Modified Wobbe Index (MWI) - Absolute Limits - Range Within Limits	 54 +5%	 40 -5%	See note 6 See note 7 See note 8
Flammability Ratio	See note 9	2.2:1	Rich: Lean Fuel/Air Ratio volume basis. See note 10
Constituent Limits, mole % Methane Ethane Propane Butane + higher paraffins (C4+) Hydrogen Carbon Monoxide Oxygen Total Inerts (N2+CO2+Ar) Aromatics (Benzene, Toluene etc.) Sulfur	 100 15 15 5 Trace Trace Trace 15 Report Report	 85 0 0 0 0 0 0 0 0 0	 % of reactant species % of reactant species % of reactant species % of reactant species % of reactant species % of reactant species % of reactant species % of total (reactants + inerts). See note 11 See note 12

Fuel Property and Contaminant Notes:

1. All fuel properties must meet the requirements from ignition to base load unless otherwise stated.
2. Values and limits apply at the inlet of the gas fuel control module, typically the purchaser's connection, FG1.
3. Minimum and maximum gas fuel supply pressure requirements are furnished by GE as part of the unit proposal.
4. The minimum fuel gas temperature must meet the required superheat as described in section III, C. Separate requirements are included for hydrocarbon and moisture superheat. The maximum allowable fuel temperature is defined in GER 4189(2).
5. Heating value ranges shown are provided as guidelines. Specific fuel analysis must be furnished to GE for proper analysis. (see section III, A)
6. See section III, B for definition of Modified Wobbe Index (MWI).
7. The upper and lower limits for MWI shown are what can be accommodated within the standard dry low NOx fuel system designs. Fuels outside of this range may need additional design and development effort. Performance fuel heating may be restricted on fuel with high inert content to stay above the minimum MWI limit.
8. Variations of MWI greater than + 5% or –5% may be acceptable for some applications, (i.e. on units that incorporate gas fuel heating). GE must analyze and approve all conditions where the 5% variation is to be exceeded. See also Section III, B for applications where the MWI varies between the +/- 5% limits.
9. There is no defined maximum flammability ratio limit. Fuel with flammability ratio significantly larger than those of natural gas may require a start–up fuel.
10. Candidate fuels, which do not meet these limits, should be referred to GE for further review. All fuels will be reviewed by GE on a case-by-case basis. (see section III, G)

11. When fuel heating for thermal efficiency improvements is utilized (e.g. Tgas > 300°F) there is a p ossibility of gum formation if excess aromatics are present. Contact GE for further information.
12. The quantity of sulfur in gas fuels is not limited by this specification. Experience has shown that fuel sulfur levels up to 1% by volume do not significantly affect oxidation/corrosion rates. Hot corrosion of hot gas path parts is controlled by the specified trace metal limits. Sulfur levels shall be considered when addressing HRSG Corrosion, Selective Catalytic Reduction (SCR) Deposition,

Flammability Limits

The flammability limits of the fuel will have an effect on combustor design that is somewhat related to that of flame velocity. In that the degree of air/fuel mixing, the velocity of fuel injection at the combustor, and the flammability limit of the all interact to define the flame front, a change in any one of these properties will change the location of the flame front. Therefore, a fuel that has a lesser lower flammability limit will sustain combustion at a location where less mixing with the air has occurred than a fuel with a greater lower flammability limit. This could mean that the flame front is located too close to the fuel nozzle resulting in equipment damage due to overheating.

Strategies for Using Alternate Fuels

As mentioned above, the effect of fuel gas composition on the combustion properties means that the turbine manufacturer should be consulted about any fuels that an operator is considering using. However, where there is an economical alternate fuel available but modifications to the turbine are not justified, the operator would normally consider firing the alternate fuel in the duct and continuing the fire the turbine on its original fuel. This strategy depends on the relative availability of the alternate fuel and the design fuel.

Summary

This section of the report has shown that gas turbines can be designed to fire a wide variety of fuels. However, any particular turbine has limits on the variability of fuel that it can accept and the manufacturer must be consulted before changing the type of fuel. High hydrogen content fuels cannot be fired in low NOx burners so it may be necessary to use SCR for NOx control unless extra allowance is provided for in the emissions regulations.

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Section D

Heat Recovery Allowance

Introduction

This section of the report provides a discussion on the heat recovery attainable from HRSGs in different plant situations and configurations. Using process simulations of an example case GE 7EA gas turbine, it provides a sensitivity analysis on the heat recovery and NOx generation with duct firing, and derives a methodology to calculate an output based heat recovery allowance assuming a control technology of choice. Further, it provides a comparison of the existing NOx guidelines, as applied to the example case, with the NOx generated utilizing today's available control technologies. It also demonstrates how the heat recovery methodology is applied to this case to calculate a heat recovery allowance.

It also provides a commentary on the types of duct burner available and their NOx generation.

Variables Affecting Heat Recovery

Several factors have an impact on the amount of heat recovery attainable in the HRSG. These are:

1. **Extent of Duct Firing**
   Duct firing can range from zero to a maximum amount prescribed by mechanical or process limitations. For no duct firing, the potential for heat recovery depends on the gas turbine exhaust condition alone. Whereas, when some duct firing occurs the heat recovery potential depends on both the gas turbine exhaust and the amount of duct firing.
   The maximum amount of duct firing is often limited by choice of boiler wall and liner construction. Material limitations range from 425°C , for carbon steel liner in double wall construction, to 1540°C for water wall construction [1]. In some situations the maximum duct firing is limited for process reasons. One such instance, common in Alberta, is the SAGD application for Once-Through-Steam-Generation (known as OTSG). In this instance the inside surface of the steam coils must remain wetted at all times to prevent excessive scaling and loss of high inside surface heat transfer coefficient. Practice has demonstrated that maximum bulk firing temperatures in the region of 800°C to 840°C ensure the tubes remain wetted at all times.
   For the worked example, a maximum bulk firing temperature of 840°C is used, which represents approximately 30% duct firing. Although this does not cover the entire range of firing, it is typical of double-wall insulated units, which are move prevalent for economic reasons. Also, the results will show the concepts can be equally applied to higher firing rates.

2. **Flue Gas Stack Exit Temperature**
   The flue gas temperature, exiting the HRSG stack, determines the proportion of heat recovered from those gases. As the stack temperature reduces, so a higher proportion of available heat is recovered. At its limit, the maximum heat recovery (determined by the minimum stack temperature) depends on the minimum temperature of the available heat sink. These vary for different HRSG applications, so this may need to be considered when developing an output based heat recovery allowance.
   For the worked example, a range of stack temperatures are considered, representing the highest and lowest commonly achievable across cogeneration applications in Alberta. For combined cycle plants the stack temperature can vary as much as 75℃ to 130℃ depending on the temperature at the pinch point between heated condensate and flue gas. For this work, the low end temperature used is 100℃, representing a typical minimum stack temperature for combined cycle power plants [(2)(3)(4)]. The high end temperature used is 215℃, representing a typical m inimum stack temperature for a Steam Assisted Gravity Drainage facility. This assumed an average boiler feedwater temperature of 200℃ and a 15℃ approach.

3. **Condition of the Gas Turbine Exhaust (flow and temperature)**
   The flow and temperature of the gas turbine exhaust will depend on the heat rate of the gas turbine. Although this affects the amount of heat recovered in the HRSG, the total heat recovered from the gas turbine, as both electricity and heat recovered from the unfired exhaust gas, will be similar for all situations.
   For the worked example this is not considered a variable.

Types of Duct Burners Currently Used

There are two types of duct burner available and used in the market today; Standard burners are offered by most burner vendors, and dual stage/recirculation Low NOx type are being offered by at least one burner vendor [(5)]. Vendors typically guarantee 38 g/GJ (heat input HHV basis) for standard burners, whereas experience with the dual stage type is limited to the United States, and no guarantees are presently offered in Canada. The vendor offering dual stage type has no units operating in Canada, and requires field experience in a range of installations in the Canadian climate before being prepared to offer guarantees. They presently have 5 or 6 projects in Canada (none yet started up) which utilize this burner type. None of these projects provide a low NOx guarantee with the burners.

The vendor offering dual stage type cannot supply qualifications because most plants operating in the US have SCRs downstream, meaning they are unable to measure burner performance against guarantee. There are two plants without downstream SCRs; however both operators will not release emissions data for liability reasons.

Although no guarantees are offered in Canada, the typical NOx generation figure for dual stage type is approximately 22 g/GJ (heat input HHV basis).

The standard burners can be used on natural gas as well as alternate gaseous fuels. However, the dual stage is only applicable to natural gas, because it has issues with fuels which are more susceptible to coking, and with fuels having high hydrogen content.

The dual stage burners occupy approximately 4 times the cross-sectional area, inside the duct, as the conventional burners. This means smaller units do not have sufficient space to cater for this type of burner. The cut-off size, above which these burners will fit inside the HRSG ducting, is approximately a 50 to 60 MW gas turbine.

Basis for Calculations

Gas Turbine

The worked example is taken from an existing Alberta project. The key parameters are:

Gas Turbine	GE-7EA
Heat Rate	11,170 kJ/kWh (LHV)
Output	76,630 kW
Ambient Temperature	17℃
Fuel	Natural Gas
Fuel LHV	43,990 kJ/kg
Exhaust Flow	964,700 kg/h
Exhaust Temperature	545℃

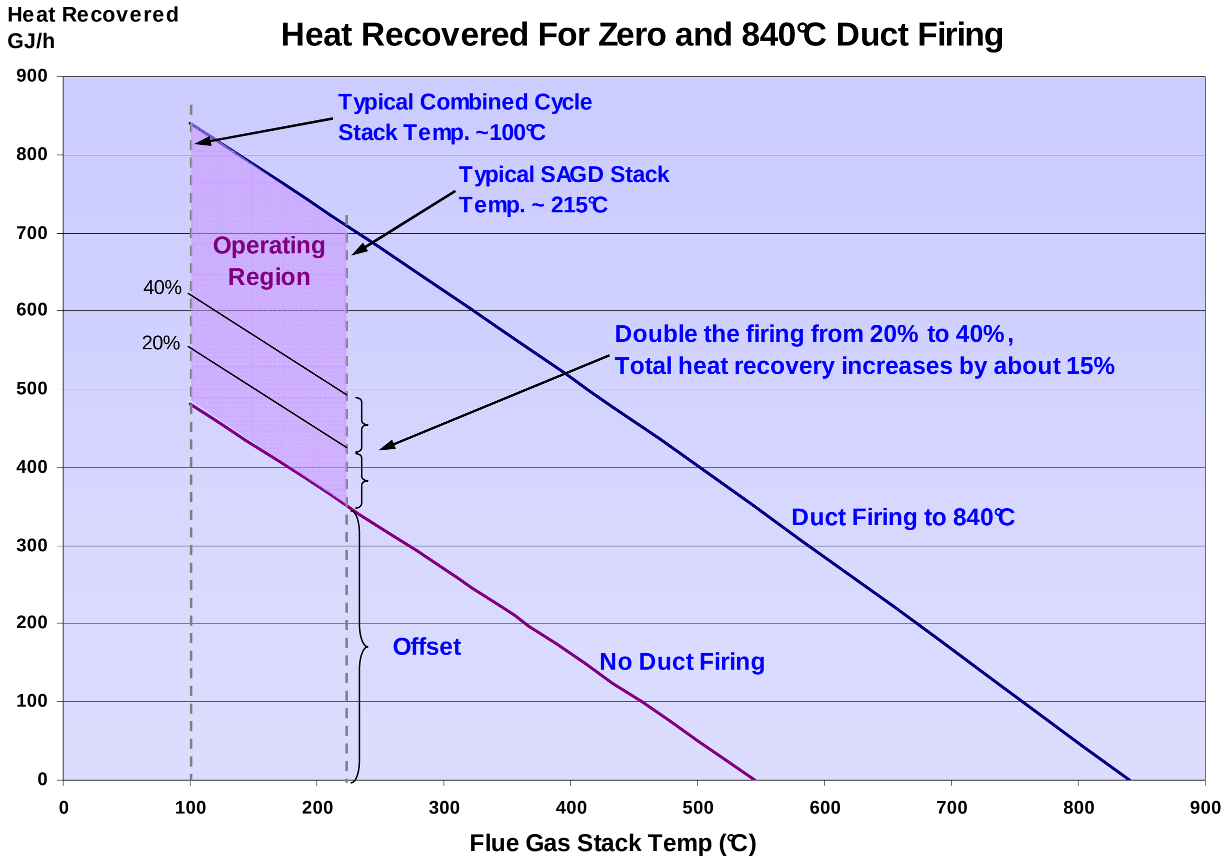
HRSG

Duct Firing	From zero firing to 840℃ bulk firing temperature
Heat Recovery	215℃ (SAGD application) to 100℃ (Combined Cycle application)
NOx Generation	38 g/GJ HHV heat input (standard burner) guaranteed 22 g/GJ HHV heat input (dual stage low NOx burner) estimated

Analysis of Duct Firing and Stack Temperature

Figure D.1 shows the amount of heat recovered for no duct firing and 840℃ firing across a range of flue gas stack temperatures down to 100℃. It shows there is a considerable offset of heat recovered associated with the gas turbine exhaust alone. As a result, the graph shows when doubling the firing from 20% to 40% the total heat recovery only increases by about 15% (for SAGD application). This will need to be considered when deriving an output based heat recovery allowance.

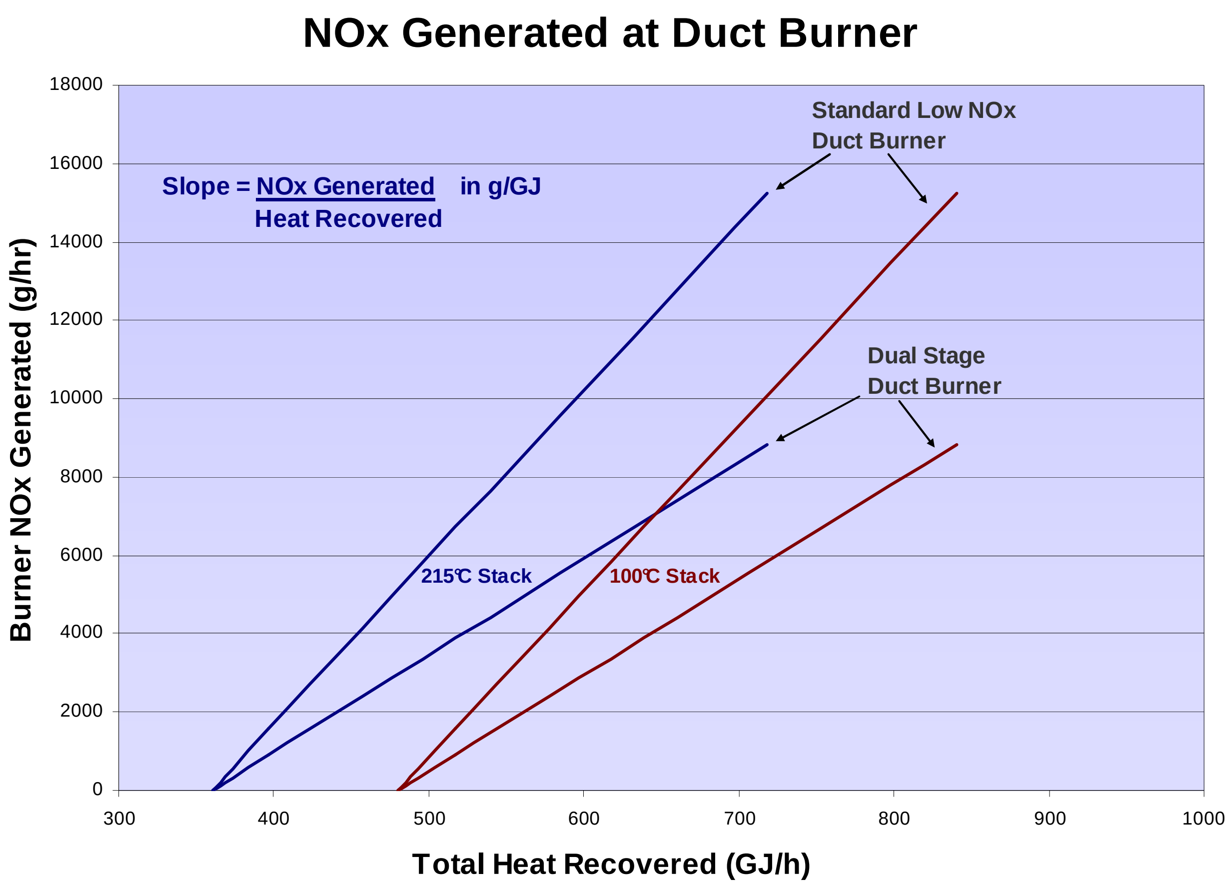
Figure D.1 – Heat Recovered Varying with Firing and Stack Temperature



Analysis of NOx Generated

Figure D.2 shows how the NOx generated at the duct burner varies with heat recovered. Both the guaranteed NOx for standard burners and the estimated NOx for dual stage type are reported. The two stack temperatures representing Combined Cycle and SAGD (100 and 215℃) are considered. The graph shows the relation ship is linear between heat recovered and burner NOx generated.

Figure D.2 – Burner NOx Generated Varying with Heat Recovered



For an output based heat recovery allowance we need a relationship between allowable NOx limit and heat recovered. This graph shows a direct relationship between guaranteed NOx generated and heat recovered, represented by the slope of the curves for each scenario. This forms the starting point for the allowable limit relationship. To determine the variance of the relationship across differing stack temperatures we plot the slope of each curve against heat recovered in Figure D.3.

Figure D.3 - Burner NOx (per unit heat recovered) Varying with Heat Recovered

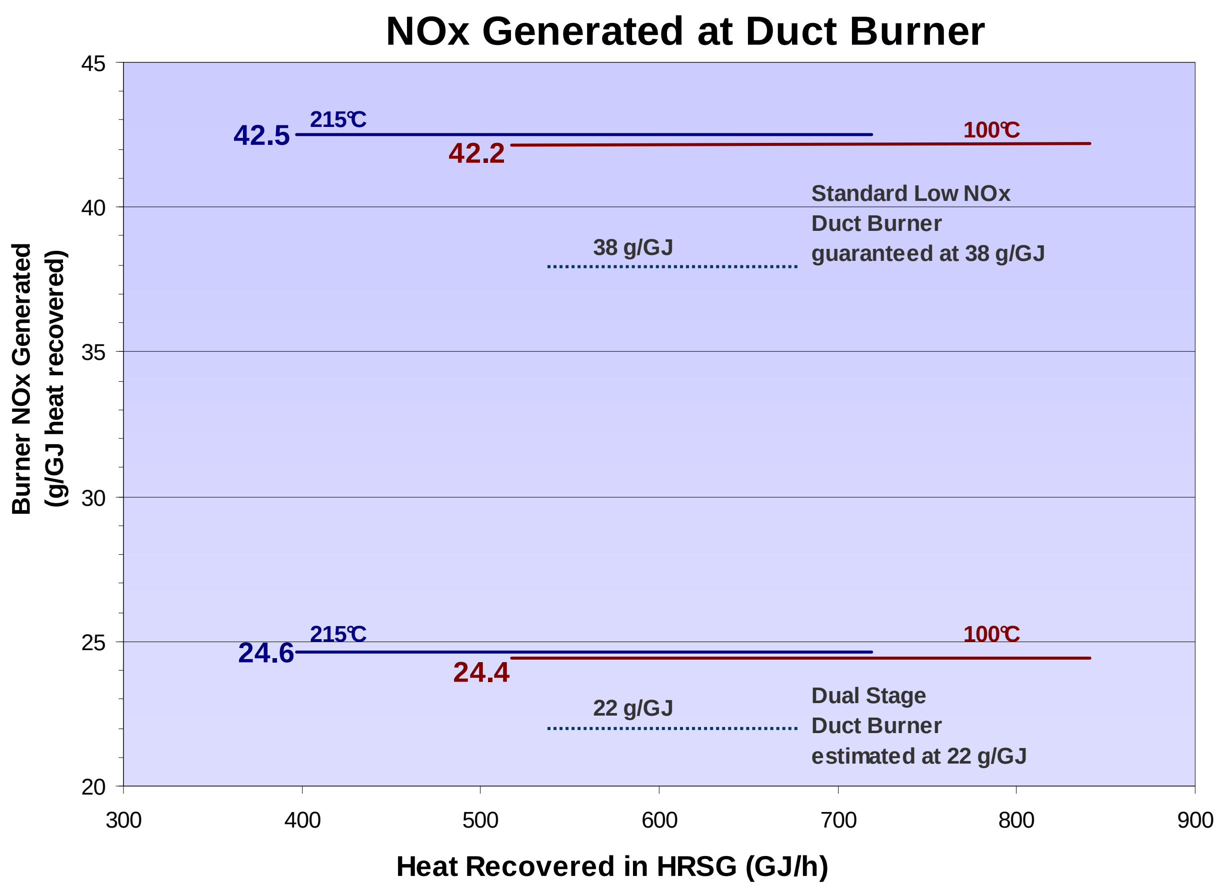


Figure D.3 shows that for a given burner type, and for the selected range of stack temperatures, the factor

$$\frac{\text{(Burner NOx generated)}}{\text{(Heat recovered)}}$$

does not vary significantly across the selected range of duct firing. Furthermore, since this factor is fairly constant, and the burner NOx generated per unit heat released is fixed, then the ratio

$$\frac{\dfrac{\text{(Burner NOx generated)}}{\text{(Burner heat released)}}}{\dfrac{\text{(Burner NOx generated)}}{\text{(Heat recovered)}}}$$

is also fairly constant. Table 1 shows a comparison of the ratio of burner NOx per unit heat released to NOx generated per unit heat recovered.

Table D.1 - Ratio of NOx per unit Heat Released to NOx per unit Heat Recovered

		Standard		Dual Stage	
Stack Temperature		100℃	215℃	100℃	215℃
Burner NOx Generated/Heat Released	g/GJ	38	38	22	22
Burner NOx Generated/Heat Recovered	g/GJ	42.2	42.5	24.4	24.6
NOx per heat released/NOx per heat recovered	-	90.0%	89.4%	90.2%	89.4%

The factor, in percentage terms, represents the efficiency of heat recovered from the heat released at the duct burners.

Method for an Output Based Heat Recovery Allowance

This section utilizes the analysis above to develop an *Output Based Heat Allowance*. It makes the assumption that an economic analysis has been carried out, and this has determined the type of control technology that will be required to satisfy a NOx emissions guideline.

The method is shown for one worked example utilizing duct burners only, followed by an adaptation to apply to Selective Catalytic Reduction.

Example Using Standard Duct Burners

The form of equation selected for the output based heat allowance is typical in industry:

(GT Power Output x A) + (Heat Output x B) = grams of NO_2 per hour equivalent

Where:

- GT Power Output is the total electricity and shaft power output expressed in GJ/h
- Heat Output is the total useful heat energy recovered from the Heat Recovery unit, expressed in GJ/h
- **A** and **B** are the allowable emission rates, expressed in grams per GJ, for the facility's power and heat recovery components respectively.

Calculate Heat Recovery Allowance Factor "B"

For this example we are using the standard burner technology with a guarantee NOx generation of 38 g/GJ heat input (HHV). We also assume that a stack temperature of 215℃ is acceptable, which means the expected HRSG efficiency for duct burning heat recovered will be approximately 89.4%.

The NOx generated per unit heat recovered will be = 38 / 89.4% = **42.5 g/GJ**

This is the Heat Recovery Allowance factor **B**, in g/GJ. If we add a margin to this factor, the additional allowance will be directly proportional to the heat recovered, thus adding a larger margin at higher heat recoveries.

Make-Up of Factor "B"

A considerable portion of the heat recovered in the HRSG is attributed to the gas turbine exhaust, not the duct firing. This means that part of the allowable NOx, calculated from the total heat recovered, is in fact attributed to the gas turbine generated NOx. Figure D.4 demonstrates this for an example case where the amount of duct firing leads to 500 GJ/h heat recovered at 215℃. We can partition this into the component hea t recoveries associated with the gas turbine and duct firing, and calculate the component NOx allowed for each.

For this example the total NOx allowance is:

42.5 (g/GJ) x 500 (GJ/h) = 21250 g/h

The base load heat recovery (when no duct firing occurs) is 350 GJ/h, and the allowable NOx for this portion of heat recovered is:

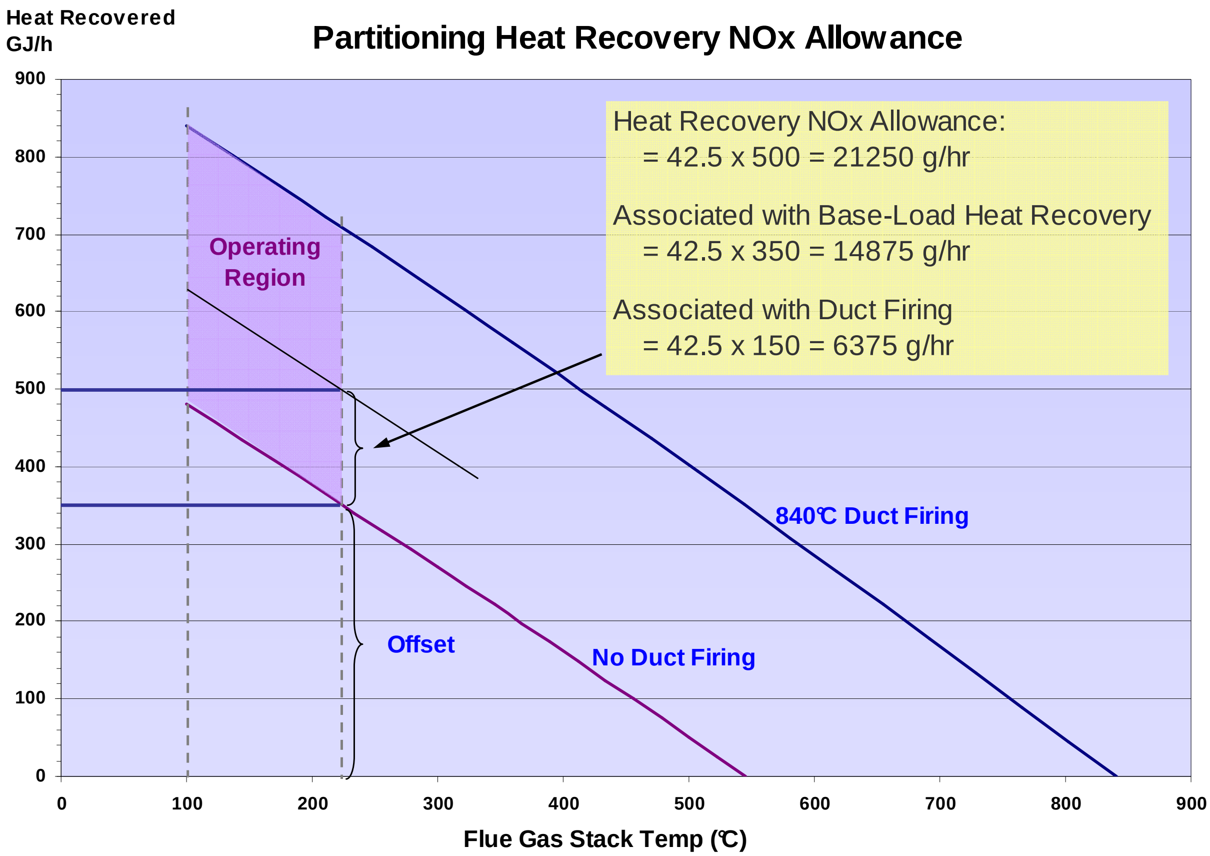
42.5 (g/GJ) x 350 (GJ/h) = 14875 g/h

And the NOx associated with the duct firing is:

42.5 (g/GJ) x 150 (GJ/h) = 6375 g/h

The 14875 g/h of allowable NOx, associated with gas turbine exhaust, should be credited against the Factor "A" otherwise this amount will act as a fixed margin in the allowable NOx formula.

Figure D.4 – Partitioning the Heat Recovery NOx Allowance



Calculate Gas Turbine Power Output Factor "A"

For this example we are using dry low NOx burner technology with typical guaranteed NOx, at the gas turbine exhaust, of 20 ppmv dry. Based on the dry exhaust flow (not corrected for 15% O_2), the NOx generated is calculated to be 29130 g/hr, which equates to 106 g/GJ gas turbine output.

Credit the 14875 g/h associated with the gas turbine exhaust and allowed for in the heat recovery factor:

29130 - 14875 = 14255 g/h

Re-calculate the adjusted NOx generated per unit of gas turbine power output:

14255 (g/h) / 76.63 (MW) / 3.6 (GJ/MWh) = **51.6 g/GJ**

This is the Gas Turbine factor **A**, in g/GJ. If we add a margin to this factor, the additional allowance will be directly proportional to the gas turbine output, thus adding a larger margin at higher outputs.

Without any margins added, the NOx allowance for this example would be:

(GT Power Output x 51.6) + (Heat Output x 42.5) = grams of NO_2 per hour equivalent

This formula tracks the NOx generated by the selected technology. In practice a margin would likely be added to account for design and operating variations.

Example Using Selective Catalytic Reduction

For this example we are using the same standard burner technology with a guarantee NOx generation of 38 g/GJ heat input (HHV), and the same stack temperature of 215°C (HRSG efficiency of 89.4% for duct burning heat recovered). In addition, we assume a *Selective Catalytic Reduction* unit is installed, and this will remove 90% of the NOx.

The NOx generated per unit heat recovered will be = 38 / 89.4% = 42.5 g/GJ

90% of NOx is removed at the SCR, thus the NOx emitted per unit heat recovered is:

10% x 42.5 (g/GJ) = **4.25 g/GJ**

This is the Heat Recovery Allowance factor **B**, in g/GJ.

Next, calculate the NOx associated with the base heat load (no duct firing):

4.25 (g/GJ) x 350 (GJ/h) = 1490 g/h

For dry low NOx burner technology with typical guaranteed NOx generation of 20 ppmv dry at the exhaust, the NOx generated by the gas turbine is 29130 g/hr.

90% of NOx is removed at the SCR, thus the NOx emitted is:

10% x 29130 (g/h) = 2913 g/h

Credit the 1490 g/h associated with the gas turbine exhaust and allowed for in the heat recovery factor:

2913 - 1490 = 1423g/h

Re-calculate the adjusted NOx generated per unit of gas turbine power output:

1423 (g/h) / 76.63 (MW) / 3.6 (GJ/MWh) = **5.16 g/GJ**

This is the Gas Turbine factor **A**, in g/GJ. Without any margins added, the NOx allowance for this example would be:

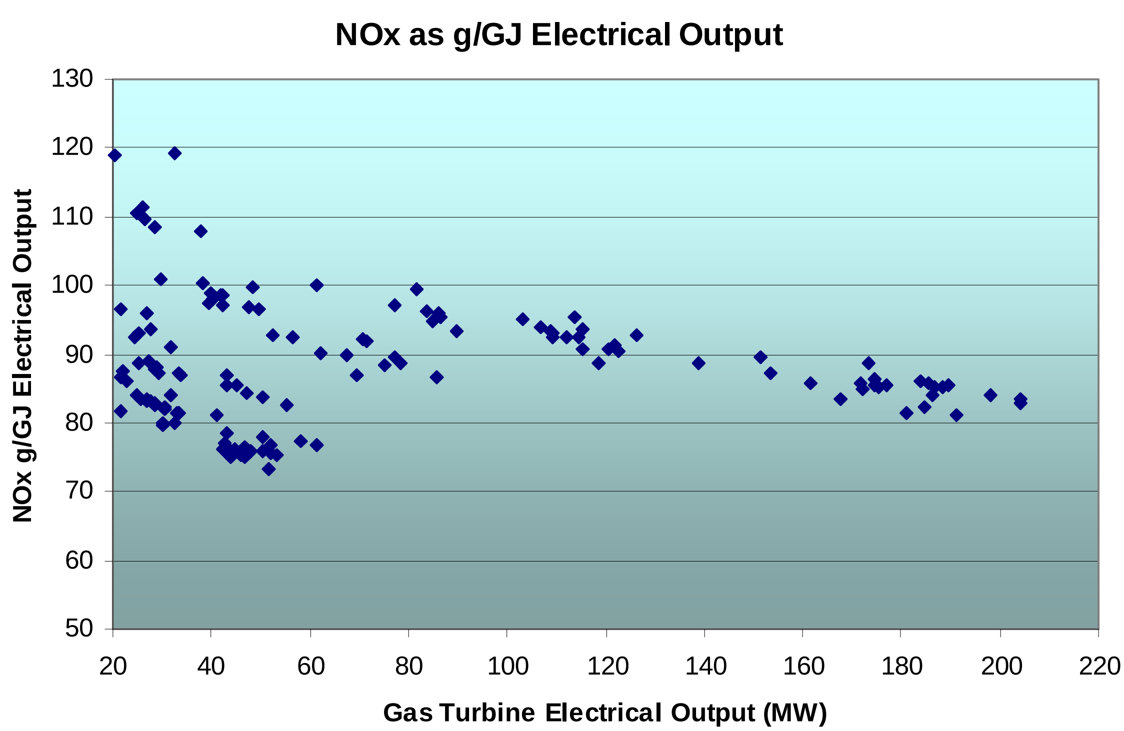
(GT Power Output x 5.16) + (Heat Output x 4.25) = grams of NO_2 per hour equivalent

Note the factors "A" and "B" are simply 10% of the previous example.

Sensitivity on Gas Turbine Parameters

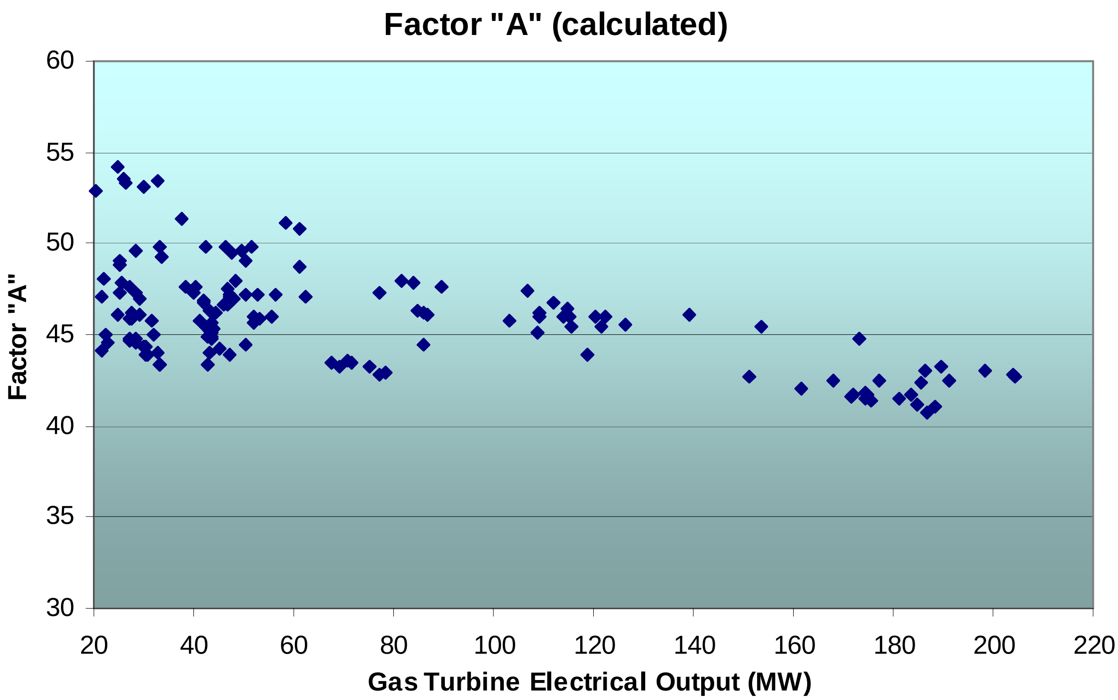
The method described above has been demonstrated for a single gas turbine and HRSG example. However, gas turbines have different heat rates, air flows, and exhaust temperatures. These factors mean that even when the gas turbine manufacturers quote the same NOx (as ppmv dry) at the exhaust, the NOx rates (as g/GJ electrical output) will be different. This is demonstrated in the following figure. From the GTPRO [(6)] database of approximately 140 gas turbines, ranging from 20 to 200 MW, Figure D.5 plots the NOx on an electrical output basis (g/GJ) assuming 20 ppmvd NOx at the exhaust. Note these calculations are approximate, based on a database of turbine heat rates, air flows, exhaust temperatures, and output powers, and assumed fuel and exhaust gas characteristics. It does make an adjustment to take account of the O_2 correction to 15%.

Figure D.5 – Gas Turbine NOx in g/GJ for a Range of Gas Turbine Sizes



This means the Factor **"A"** calculated will vary also. Figure D.6 shows the calculated Factor "A" for each gas turbine.

Figure D.6 – Factor "A" (g/GJ) Calculated for a Range of Gas Turbine Sizes



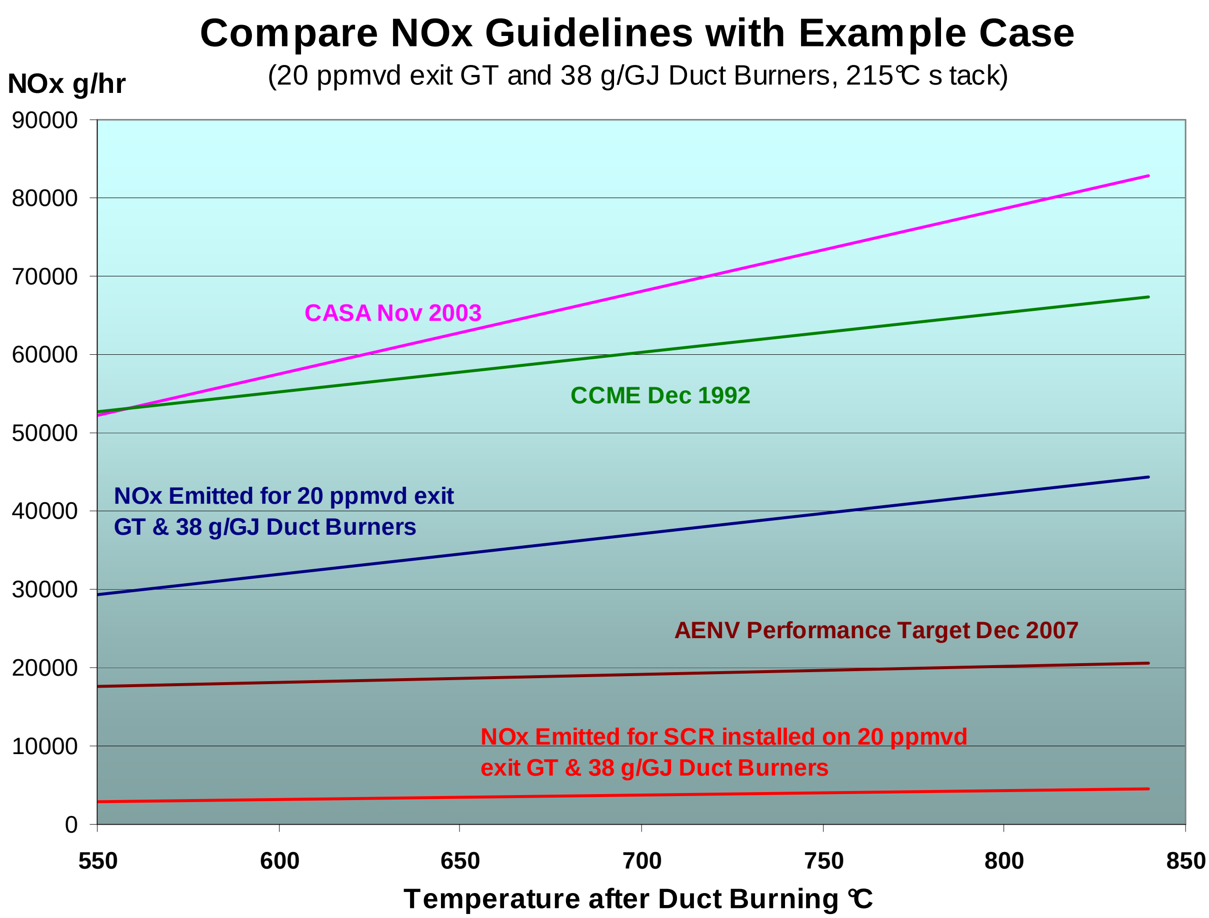
Thus it is important to take this into account when applying an output based allowance to gas turbines.

Comparison with Existing NOx Guidelines

It is useful to understand where the existing guidelines stand in comparison to commonly used control technologies today. Also, for output based NOx allowances, it is useful to understand how the NOx allowance reduces for low heat recoveries, and how this compares with actual NOx emitted for the same commonly used control technologies.

Figure D.7 shows the NOx allowance for the example case with a 215℃ stack temperature, as applied by the guidelines from CCME (1992) [7], CASA (2003) [8] and AENV (performance target 2007) [9]. The NOx emitted for the example case are also shown, for the case with SCR and without. The example case represents a SAGD situation, where maximum (840℃) duct firing would yield approximately 350 te/h steam at about 11200 KPag.

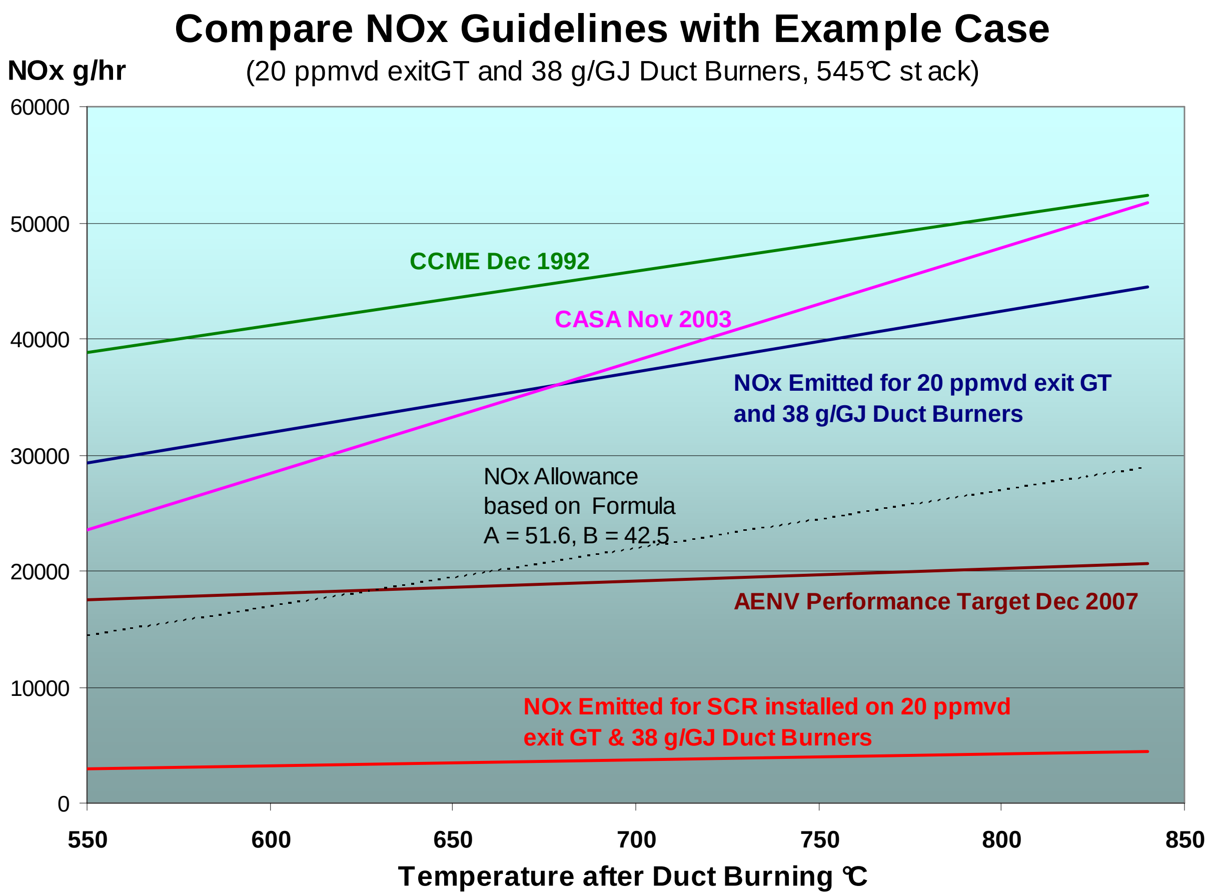
Figure D.7 – Comparison of NOx Guidelines with Example Case NOx Generated



The graph shows the example case without SCR is able to meet the CCME (1992) (7) and CASA (2003) (8) guidelines, but not the AENV performance target (9). Only the example case utilizing an SCR can meet the requirements of the AENV performance target (9).

When heat recovery in the HRSG is reduced then the output based NOx allowance will also reduce the total NOx allowance. Figure D.8 shows the NOx allowance for the example case with a 545℃ stack temperature, as applied by the guidel ines from CCME (1992) (7), CASA (2003) (8) and AENV performance target (9). Also included is a NOx allowance using the calculated formula A=51.6 and B=42.5.

Figure D.8 – Comparison of NOx Guidelines with Example Case NOx Generated



The graph shows the example case without SCR is able to meet the CCME (1992) [(7)] guidelines at all duct firing conditions, and the CASA (2003) [(8)] and lower duct firing. It is not, however, able to meet the AENV performance target [(9)] or the calculated formula (A=51.6, B=42.5). Only the example case utilizing an SCR can meet the requirements of all the guidelines.

Generic Method for Heat Recovery Allowance

This section describes, in generic terms, how to calculate the Heat Recovery Allowance factors for a selected control technology. The allowance will use the formula presented above:

(GT Power Output x A) + (Heat Output x B) = grams of NO_2 per hour equivalent

Where:

- GT Power Output is the total electricity and shaft power output expressed in GJ/h
- Heat Output is the total useful heat energy recovered from the Heat Recovery unit, expressed in GJ/h
- **A** and **B** are the allowable emission rates, expressed in grams per GJ, for the facility's power and heat recovery components respectively.

First calculate the minimum required efficiency for duct burning heat recovered. This is calculated as:

$$\frac{\text{Heat Recovered at duct burning X} - \text{Heat Recovered at no duct burning}}{\text{Duct burning heat input X (HHV basis)}} \times 100\%$$

Divide the NOx generation rate of the duct burner technology (g/GJ heat HHV input) by the minimum required efficiency for duct burning heat recovered. This provides the Factor **B** in terms of NOx emitted per unit of heat recovered. If an SCR is also expected then multiply this factor by the maximum percentage of NOx slip downstream of the SCR, to get the Factor **B** for SCR implemented. For example, if the SCR must remove at least 85% of NOx from the stack gases, then the factor **B** is multiplied by 100% – 85% = 15%.

Next calculate Factor **A**. First select gas turbine operating parameters for a turbine in the size range being considered. To ensure most turbines will be able to achieve the desired NOx emissions, select a turbine that has a high NOx generated per unit electrical power output. For this turbine, calculate the heat recovered from the exhaust gas when no duct firing occurs, and multiply this by Factor **B** to obtain the allowable NOx associated with the heat recovery of the gas turbine exhaust.

Calculate the NOx generated in gas turbine and deduct the allowable NOx associated with the heat recovery of gas turbine exhaust. Divide this value by the electrical power output (GJ/h) to obtain Factor **A**. If an SCR is also expected then multiply this factor by the maximum percentage of NOx slip downstream of the SCR, to get the Factor **A** for SCR implemented (same as for Factor **B**).

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1) Pat Albert, Cogeneration On-Site Power Magazine, 02-May-2005, “HRSG Options for CHP Plants”.

2) Meherwan P. Boyce, ASME Press, 2002, “Handbook for Cogeneration and Combined Cycle Power Plants”, p91.

3) http://www.metcalfenergycenter.com/facts/CC_description.doc, “How Does A Combined Cycle Power Plant Work? A Tour of the Metcalf Energy Center”

4) A. Ragland, W. Stenzel, Proceedings of 2000 International Joint Power Generation Conference, “Combined Cycle Heat Recovery Optimization”.

5) Coen Company Inc, Woodland, CA, Discussions with burner vendor specialist.

6) GT Pro is licensed combined cycle design software from Thermoflow Inc, MA

7) Canadian Council of Ministers of the Environment, December 1992, “National Emissions Guidelines For Stationary Combustion Turbines”.

8) Clean Air Strategic Alliance Electricity Project Team, November 2003, “An Emissions Management Framework for the Alberta Electricity Sector Report to Stakeholders”.

9) Alberta Environment, December 2007, “Interim Emission Guidelines for Oxides of Nitrogen for New Boilers, Heaters and Turbines using Gaseous Fuels OSEMD-OO-PP2.

Section E.

Jurisdictional Review

Summary of Findings

In order to put the NOx emission limits in context with other developed countries, this study included a review of the legislation and regulations in Canada, the United States, parts of western Europe and Japan. Table E.1 below summarizes the main points of the governing regulation regarding NOx emission limits for the jurisdictions that were reviewed. Further detail is provided in the descriptions which follow.

Table E.1 - Summary of Regulations in Other Jurisdictions

	EMISSION LIMITS FOR NEW NATURAL GAS FIRED UNITS						SPECIAL ALLOWANCE FOR COGEN SYSTEM?(5)	SPECIAL LIMITS FOR NON-ATTAINMENT?	CAP AND TRADE?	COMMENTS	Governing Legislation/Regulation/Guidelines
	Emission Limit			Emission Limit							
	Size Limit	Emission Limit, ppmv(1)	Emission Limit, g/MWH(1)	Size Limit	Emission Limit, ppmv(1)	Emission Limit, g/MWH(1)					
CCME 1992	3 - 20 MW		864(3)	>20		504(3)	Allows 140 g/MWh for heat recovery(4)	Allowed		Because of the higher efficiency of cogen systems, the heat recovery allowance allows a higher ppmv NOx in the flue gas	
Cda - BC	3 - 25 MW		80mg/m3	>25 MW		17mg/m3	No	No	No		Emission Criteria for Gas Turbines (December 1992)
Cda - BC				>25 MW		48 mg/m3	No	No	No	Note (7)	Emission Criteria for Gas Turbines (December 1992)
Cda - SK			Per permit				N/A	No	No		Chapter C-12.1 of the Clean Air Act
Cda - MB			Per licence				N/A	No	No		CCSM cE125 " The Environment Act"
Cda - ON		N/A	N/A		N/A	N/A	Yes	No		Site wide facility NOx is targeted	Ontario Regulation 194/05
USEPA	14.6-250 MW	25		>250 MW	15		Yes			Allows 150 ppmv NOx at ambient temperatures < -20F or turndown below 75%	40CFR60 Subpart KKKK
Alaska	Same as US EPA							Yes			18AAC50 -Env.Conservation Chpt 50 Air Quality Control
California (PUC)		2 ppm Combined Cycle					Allows 32 g/MWh if efficiency >60%		2012	California: Public Utilities Code	
California (Southern)		2.0 (2)			2.0(2)			Yes	2012	South Coast Air Quality Management District - Severe ozone non-attainment	
Maine	<220 MW		29	≥220 MW		20		No		Regulations for power generation but not specifically for gas turbine or cogen systems	EPA-Approved Maine Regulations; Chapter 145 - Nox Control Program
Michigan	>73 MW (NG Fired)		310	>73 MW (non-NG Fired)		387				Regulations for power generation but not specifically for gas turbine or cogen systems	R 336.1801 Emission of oxides of nitrogen from non-sip call stationary sources
Texas	Any	5 ppm Simple Cycle, 2_ppm Combined Cycle		Elec Generating >10MW	64 g/MWh		Yes	Yes		Dry Low NOx burner, water or steam, SCR	
East & Central Texas		42						Yes			Title 30, Part 1, Chapter 117, Rule 117.3010
Washington	Same as US EPA										WAC 173-400-115; Standards of Performance for New Sources (Makes reference to 40CFR60 Subpart KKKK)

Table E.1 - Summary of Regulations in Other Jurisdictions

	EMISSION LIMITS FOR NEW NATURAL GAS FIRED UNITS						SPECIAL ALLOWANCE FOR COGEN SYSTEM?(5)	SPECIAL LIMITS FOR NON-ATTAINMENT?	CAP AND TRADE?	COMMENTS	Governing Legislation/Regulation/Guidelines
	Emission Limit			Emission Limit							
	Size Limit	Emission Limit, ppmv(1)	Emission Limit, g/MWH(1)	Size Limit	Emission Limit, ppmv(1)	Emission Limit, g/MWH(1)					
Japan				> 50 L/hr3 fuel rate	70		No	Reguired in severe non-attainment areas	No	General requirement that new combustion facilities NOx emissions not exceed 60 to 400 ppmv	Environmental Quality Standards in Japan - Air Pollution Control Law
Netherlands	>50MW (NG Fired)		162	>50 MW (non-NG Fired)		234	Duct burner emission allowance can be included in emission calc	Allowed	Yes	Gas turbines on offshore platforms exempt. Cogen must be applied if technically and economically feasible	Besluit emissie-eisen stookinstallaties milieubeheer A (aka "Bees" A)
Germany				>50 MW	24		36 ppmv allowed for cogen or combined cycle plants	Allowed		Gas turbines on offshore platforms exempt. Cogen must be applied if technically and economically feasible	Thirteenth Ordinance of Federal Emission Control Act (2004)
Norway				>50 MW	24		36 ppmv allowed for cogen systems		NOx emissions are taxed	Emission limits apply to onshore combustion turbines	Protocol to the 1979 Convention on Long-Range Transboundary Air Pollution to Abate Acidification, Eutrophication and Ground-Level Ozone

Notes

(1) Conversion between ppmv and g/MW-hr are approximations which are dependant on specific gas turbines. The MW is based on energy output including both power and steam
(2) All but the smallest units must meet BACT which is LAER in California California has the goal to promote cogen to reduce energy consumption and GHG emissions
(3) Dec 2007 interim guidelines set a Performance Target of 73 g/MW-hr based on LHV heat input which is roughly equivalent to 210 g/MW-hr output or 12 ppmv NOx in flue gas
(4) Dec 2007 interim guidelines set a Performance Target of 28 g/MW-hr based on HHV heat input
(5) Regulations based on energy output favor cogen because they allow more NOx emissions when energy is recovered. Regulations based on ppmv are neutral or penalize cogen
(6) All ppmv values are corrected to 15% O2
(7) Apply to gas pipeline application and other installations where selective catalytic reduction (SCR) is demonstrated to be inappropriate.

Details of NOx Control Legislation

In addition to the basic information about NOx emissions limits mandated by jurisdictions outside Alberta, the study collected information on several other questions that are relevant to the Alberta case:

- Does the jurisdiction make provision for encouraging alternate fuel use in the regulations?
- Are the NOx emissions in the jurisdiction subject to cap and trade limits?
- Is the climate in the jurisdiction similar to Alberta's?

Canada

Jurisdiction: British Columbia

Name of governing legislation: The BC government has published "Emission Criteria for Gas Turbines" which were developed based on the BC Ministry of Environment's Best Available Control Technology (BACT) policy.

Provision for alternate fuels: No – The "Emission Criteria" document only makes reference to natural gas and oil fuels.

Provision for cap and trade: No

Synopsis of governing legislation:
The Emission Criteria for Gas Turbines were developed based on the Ministry of Environment's Best Available Control Technology (BACT) policy. These criteria update and elaborate on the criteria set for natural gas combustion in the Pollution Control Objectives for Food Processing, Agriculturally Oriented and Other Miscellaneous Industries of British Columbia, published in 1975.

Ministry of Environment policy states that regional Environmental Protection Managers must use BACT criteria as a starting point when establishing minimum permit limits for new or modified facilities.

Climatic conditions: The BC guidelines make no provision allowing different NOx emission limits at different operating temperatures. BC's climate has similar temperature ranges to Alberta's.

Jurisdiction: Ontario

Name of governing legislation: Ontario Regulation 194/05 of the Environmental Protection Act

Provision for alternate fuels: No – The Ontario regulation does not make an explicit exemption or allowance for cogeneration facilities that are fired with fuels other than natural gas. The regulations are based upon facility-wide NOx emission caps rather than intensity based limits on each piece of equipment. However, wherever new facilities are being contemplated, there is a requirement to use a BACTEA review to determine the appropriate NOx control technology to employ. A developer planning to use a fuel other than natural gas might be able to argue that the typical NOx control technologies are not appropriate for his situation under the BACTEA guideline which allows for the "Elimination of technologies not used at comparable facilities" or the "Elimination of technically infeasible control technologies". For example DLN burners would be infeasible in a facility powered by high-hydrogen refinery fuel gas.

Provision for cap and trade: Emissions for existing facilities are capped. "New source set-aside limits" are available for new emitters who want to establish operations in the province.

Synopsis of governing legislation: The regulation establishes a NOx emission baseline in tonnes per year for individual petroleum sector facilities based on their actual emissions during the 2006 to 2009 timeframe. Emission limits for individual facilities will be calculated based on their baseline emissions and applying various adjustments which are defined in the regulation.

Climatic conditions: The ON guidelines make no provision allowing different NOx emission limits at different operating temperatures. ON's climate has similar temperature ranges to Alberta's, however, most of the industrial development is in the southern part of the province which rarely experiences the low temperature extremes which occur in Alberta.

United States

Jurisdiction: U.S. Environmental Protection Agency (EPA) federal regulations

Name of governing legislation:
Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES
Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Provision for alternate fuels:
Yes – regulation makes provision for operating using fuels other than natural gas by allowing higher NO_X emission limits (see table in "Synopsis of Legislation section")

Paragraph § 60.4325 of the legislation states "If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel."

Provision for cap and trade:
No

Synopsis of governing legislation:
Table E.2 summarizes the NO_X emission limits for different turbine sizes, alternate fuels and geographic locations.

Table E.2 – US EPA NOx Emission Standard

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/hr	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MW-hr)
New turbine firing natural gas	> 50 MMBtu/hr and ≤ 850 MMBtu/hr	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MW-hr)
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/hr	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MW-hr)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/hr	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MW-hr)
New turbine firing fuels other than natural gas	> 50 MMBtu/hr and ≤ 850 MMBtu/hr	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MW-hr)
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/hr	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MW-hr).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbines operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MW-hr)

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbines operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MW-hr)
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MW-hr)

Climatic conditions:
As shown in Table E.2, the EPA federal regulation makes provision for turbines operating in cold temperatures by allowing for higher emission limits than those in warmer temperatures.

Jurisdiction: California

Name of governing legislation:
California Air Pollution Control Laws
PUBLIC UTILITIES CODE
Part 2 Specific Public Utilities
Chapter 8 Energy Efficiency Systems

Provision for alternate fuels:
No

Provision for cap and trade:
No

Synopsis of governing legislation:

- Combined heat and power systems (CHP) or cogen systems in California are required to have a minimum efficiency of 60 percent.
- CHP systems must have NOX emissions of no more than 0.07 lb/MW-hr.
- CHP systems that meet the 60 percent efficiency standard may take a credit to meet the applicable NOX emissions standard of 0.07 lb/MW-hr. Credit shall be at the rate of one MW-hr for each 3.4 million British thermal units of heat recovered.

Climatic conditions:
The climate of most of California is substantially warmer than Alberta. However, the climate of northern California can be cool and wet.

California is one of few states to offer regulations that apply specifically to CHP systems. CHP systems are required to be cost effective, technologically feasible, and environmentally beneficial. Thereby supporting the intent of the regulation to advance the efficiency of the state's use of natural gas by capturing unused waste heat, and in so doing, help offset the growing crisis in electricity supply and transmission congestion in the state.

Jurisdiction: Michigan

Name of governing legislation:
DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
AIR POLLUTION CONTROL

(By authority conferred on the director of the department of environmental quality by sections 5503 and 5512 of 1994 PA 451, MCL 324.5503 and 324.5512, and Executive Reorganization Order No. 1995-18, MCL 324.99903)

PART 8. EMISSION LIMITATIONS AND PROHIBITIONS- OXIDES OF NITROGEN

R 336.1801 Emission of oxides of nitrogen from non-sip call stationary sources.

Provision for alternate fuels:
Yes – 0.25lb /mmBTU NOx emissions permitted when firing gases other than natural gas vs. 0.20 lb/mmBtu when firing natural gas

Provision for cap and trade:
No

Synopsis of governing legislation:
(2) An owner or operator of a fossil fuel-fired, electricity-generating utility unit which has the potential to emit more than 25 tons each ozone control period of oxides of nitrogen and which serves a generator that has a nameplate capacity of 25 megawatts or more shall comply with the emission limits during the ozone control period as follows:
("Ozone control period" means the period of May 31, 2004, through September 30, 2004, and the period of May 1 through September 30 each subsequent and prior year.)

(a) By May 31, 2004, meet the least stringent of a utility system-wide average oxides of nitrogen emission rate of 0.25 pounds per million British thermal units heat input or an emission rate based on a 65% reduction of oxides of nitrogen from 1990 levels.

(4) By May 31, 2004, an owner or operator of a fossil fuel-fired emission unit which has the potential to emit more than 25 tons of oxides of nitrogen each ozone control period, except for an emission unit that is subject to subrule (2) of this rule, and which has a maximum rated heat input capacity of more than 250 million British thermal units per hour shall comply with the following provisions, as applicable:

(a) An owner or operator of a fossil fuel-fired, electricity-generating utility unit which serves a generator that has a nameplate capacity of less than 25 megawatts which has a maximum rated heat input capacity of more than 250 million British thermal units per hour shall comply with the appropriate oxides of nitrogen emission limit in ***Table 81*** of this rule.

Table E.3 – Michigan Regulations "Table 81"

Table 81

Boilers and process heaters with heat input capacity of 250 million Btu or more oxides of nitrogen (NO_x) emission limitations (pounds NO_x per million Btu of heat input averaged over the ozone control period)

Fuel type	Emission limit (lb/MMBtu)
Natural gas	0.20
Distillate oil	0.30
Residual oil	0.40
Coal (1) Coal spreader stoker (2) Pulverized coal fired	 0.40 0.40
Gas (other than natural gas)[1]	0.25

For units operating with a combination of gas, oil, or coal, a variable emission limit calculated as the heat input weighted average of the applicable emission limits shall be used. The emission limit shall be determined as follows:

Emission limit = a(0.20) + b(applicable oil limit) + c(applicable coal limit) + d(0.25)

Where:
a = Is the percentage of total heat input from natural gas
b = Is the percentage of total heat input from oil
c = Is the percentage of total heat input from coal
d = Is the percentage of total heat input from gas (other than natural gas)

[1]This may include a mixture of gases. In this case, natural gas may be part of the mixture.

Climatic conditions: Regulation makes no provision for different ambient temperatures

Jurisdiction: Texas

Name of governing legislation:
TITLE 30 Environmental Quality
PART 1 Texas Commission on Environmental Quality
CHAPTER 116 Control of Air Pollution by Permits for New Construction or modification – Amended Air Quality Standard Permit for Electric Generation Units

Provision for alternate fuels:
Yes – The limit for units combusting landfill gas, stranded oilfield gas, digester gas, and other gaseous and liquid renewable fuels would increase allowable NO_X emissions from 1.77 to 1.90 lb/MW-hr. Gaseous and liquid renewable fuels (gaseous and liquid fuels must contain at least 75 percent landfill gas, digester gas, stranded oilfield gas, or renewable fuel content by volume) would be required to comply with the 1.90 lb/MW-hr NO_X emission limit. Ref.: Air Quality Standard Permit for Electric Generating Units, as amended May 16, 2007.

Provision for cap and trade: No
Synopsis of governing legislation:

- The Texas Commission on Environmental Quality (TCEQ) requires the use of Best Available Control Technology (BACT) to meet the emissions standards set in the Texas Administrative Code (TAC). Table E.4 summarizes the NOX emission limits and required BACT.

- CHP systems may take credit the rate of one MW-hr for each 3.4 million British thermal units of heat recovered, provided that the heat recovered must equal at least 20 percent of the total energy output of the CHP system.

Table E.4 - Texas. NO_X Emission Standards and BACT Requirements

Source	Minimum Acceptable Control for NO_X Emission	Control Efficiency or Details
Gas-fired Turbine; Less than 2,500 hours per year	9-15 ppmvd at 15 percent O_2	Dry low NO_X burner; Selective catalytic reduction
Gas-fired Turbine; Simple Cycle	2 ppmvd at 15 percent O_2	Dry low NO_X burner; Selective catalytic reduction
Gas-fired Turbine; Combined Cycle	2 ppmvd at 15 percent O_2	Dry low NO_X burner; Selective catalytic reduction
Gas-fired Turbine; Combined Cycle with Duct Burner	5 ppmvd at 15 percent O_2	Dry low NO_X burner; Selective catalytic reduction
Electric Generating Units; Greater than 10 MW	0.14 lb/MW-hr (over 300 hr/year); 0.38 lb/MW-hr (under 300 hr/year)	
Electric Generating Units; Less than 10 MW; East Texas	1.90 lb/MW-hr Firing landfill gas, oil field gas, or digester gas;	Less than 0.5 grains H_2S or 30 grains sulfur
	0.14 lb/MW-hr (over 300 hr/year); 0.47 lb/MW-hr (under 300 hr/year)	Units installed on or after 1/1/2005
Electric Generating Units; Less than 10 MW; West Texas	3.11 lb/MW-hr (over 300 hr/year); 21 lb/MW-hr (under 300 hr/year)	

Climatic conditions:
The climatic conditions in Texas are not comparable to Alberta, Canada. However, Texas rules were included because Texas has stringent NO_X emissions standards and requires BACT to meet emissions standards.

Europe

Jurisdiction: The Netherlands

Name of governing legislation: Decree on emission limits for combustion plants, environmental management (Besluit emissie-eisen stookinstallaties milieubeheer A or "Bees A") which falls under The Air Pollution Act (Wet inzake de luchtverontreiniging or Wlv),

Provision for alternate fuels: The regulation makes provision for higher NOx emissions for units firing fuels other than natural gas (65 g/GJ versus 45 g/GJ).

Provision for cap and trade: Yes - The Dutch emissions trading program for NOx was developed as part of national policy to comply with the EU directive on National Emission Ceilings (NEC Directive).

According to this directive, the Netherlands are obliged to reduce overall NOx emissions from 490 kilotons in 1995 to 260 kilotons in 2010. Negotiations with the major industrial sectors resulted in a 2010 target for the industry of 55 kilotons (relative to a 1995 baseline level of 210 kilotons). To limit the costs of this significant reduction, a trading system was introduced. Various studies had revealed that the costs of NOx abatement would vary between installations but that these costs could be reduced by implementing a system of emissions trading.

The Dutch NOx emissions trading programme differs markedly from other Cap & Trade programmes such as the European trading programme for CO2 emissions. The NOx programme is based on relative caps, directly related to the activity level of the facility. An installation builds up NOx emission rights in the course of the year. The Performance Standard Rate (PSR) for regular combustion sources (which are responsible for 85 % of total NOx emissions under the scheme), is defined as grams of NOx per unit of energy (GJ) used in the facility. There are specific process PSRs too, that apply to industrial processes such as steel production, glass manufacturing and nitric acid production, which account in total for about 15 % of industrial NOx emissions.

In the Netherlands, the environmental legislation is based on the Environmental Management Act (EMA). Companies are granted a NOx permit by the Netherlands Emission Authority if their monitoring plan, that is part of the permit, is shown to be in full compliance with the national monitoring regulation. The number of NOx emission allowances the operator of an establishment accumulates during a calendar year corresponds to a PSR, a figure that is determined each year. There is one figure for NOx-combustion installations and there are several figures for the different processes. These figures are determined for the whole of the first trading period, ending in 2010, showing a downward tendency in order to meet the NEC (national emission ceiling within EU scope) objectives in 2010.

Companies must hand in their yearly emission report by the Dutch Emissions Authority before the first of April. This report must be submitted for approval to a verification body that is accredited by the Dutch Accreditation Council. After the operator has handed in his emission report a number of allowances will be added to his personal NOx-account, that is registered by the Dutch Emissions Authority.

Synopsis of governing legislation: See above
Article 10C of the "Bees A" legislation encourages the used of cogeneration by requiring that for combustion installations with a thermal capacity equal to, or greater than, 50MW which were permitted or expanded after November 27, 2002, the technical and economic feasibility of combined heat and power must be investigated. When it appears to be feasible, combined heat and power must be applied.

Climatic conditions: No provision for operating temperature.

Jurisdiction: Norway

Name of governing legislation: Protocol to the 1979 Convention on Long-Range Transboundary Air Pollution to Abate Acidification, Eutrophication and Ground-Level Ozone

Provision for alternate fuels: No

Provision for cap and trade: NOx emissions are taxed.

Synopsis of governing legislation: The legislation creates a frame work under which business entities may either agree to undertake reduction in NOx emissions or pay a tax per unit mass of NOx emitted. The tax is directed to a fund which will be used to finance NOx reduction measures.

The NOx emissions limits apply to on shore gas combustion turbines over 50MWth capacity. The limit value for new installations running on natural gas is 50 mg/m3 but increases to 75mg/m3 if "combustion turbine is used in a combined heat and power system".

Climatic conditions: Similar temperature extremes as Alberta.

Jurisdiction: Germany

Name of governing legislation: NOx emissions from gas turbine plants are regulated through the Thirteenth Ordinance on the implementation of the Federal Immision Control Act, 2004.

Provision for alternate fuels: Yes – The regulation allows for increased NOx emission limits for gas turbine plants burning "Other gaseous fuels" rather than natural gas (120 mg/m3 versus 50 mg/m3).

Provision for cap and trade: No

Synopsis of governing legislation: Legislation contains published NOx emissions limits for gas turbines with a rated thermal input of 50MW or more. Basic limit is 50mg/m3 but increases to 75mg/m3 for cogen systems.

Article 7 of the governing legislation mandates that when a plant is constructed or substantially changed the operator has to implement requirements for combined heat and power generation unless this is technically impossible or disproportional.

Climatic conditions: Somewhat applicable to Alberta.

Jurisdiction: Japan

Name of governing legislation:
Environmental Quality Standards in Japan - Air Pollution Control Law

Provision for alternate fuels:
No

Provision for cap and trade:
No

Synopsis of governing legislation:
The table below summarizes the NO_X emission limits for different boiler sizes and alternate fuels.

Table E.5 – Summary of NOx Emission Limits in Japan

Types	Specification	Types	NO_X	
			Scale	Standard
Boiler.[*1]	Heating area[*2]: 10 m^2 or above. Burner combustion rate: 50 L/h[*3] or above.	Gas boiler.[*4]	< 10,000 m^3	150 ppm
			10,000 – 40,000 m^3	130 ppm
			40,000 – 500,000 m^3	100 ppm
			>500,000 m^3	60 ppm
		Liquid boiler or gas and liquid boiler.[*4]	< 10,000 m^3	180 ppm
			10,000 – 500,000 m^3	150 ppm
			>500,000 m^3	130 ppm
		Black liquir[*5] boiler or black liquir and gas or liquid fuel boiler.[*4]	< 10,000 m^3	180 ppm
			10,000 – 500,000 m^3	150 ppm
			>500,000 m^3	130 ppm
		Liquid fuel boiler (heating area is less than 10 m^2)[*4]		260ppm
		Coal boiler.[*4]	< 40,000 m^3	300ppm
			40,000 - 700,000 m^3	250ppm
			> 700,000 m^3	200ppm
		Solid fuel boiler.[*4] (others whose heating area is 10 m^2 or above).	< 40,000 ^{3}	300ppm
			40,000 - 700,000 m^3	250ppm
			> 700,000 m^3	200ppm
		Solid fuel boiler (heating area is less than 10 m^2)[*4]		350ppm
		Boilers[*4] (others).	< 10,000 m^3	180 ppm

Types	Specification	Types	NO_X	
			Scale	Standard
			10,000 – 500,000 m^3	150 ppm
			>500,000 m^3	130 ppm
Gas turbine engine.	Fuel combustion rate: 50 L/h*3 or above.	Gas turbine engine.		70 ppm

*1: Hot blast boilers are included. Boilers that use electricity or waste heat alone are excluded.
*2: Calculated in accordance with the ordinance of the Prime Minister's Office (called simply as "heating area" hereafter).
*3: Calculated in terms of heavy oil.
*4: Excluding a boiler that is auxiliary to a catalyzer regeneration tower or fluidized bed cracker used for refining petroleum.
*5: Produced in the paper pulp production process.

For combustion, synthesis or degradation in a boiler or a waste incinerator

- Emission standard for each facility/scale
    - New facilities: 60 - 400 ppm
- Regulation of total emission
    - It is set at each area/factory based on the total emission reduction plan.

Climatic conditions:
The climate of northern Japan is cold in the winter with average temperatures ranging from 24-32°F. During the summer the weather is warm with the average daily temperature ranging from 60-75°F. Northern Japan shares the same latitude as the northern U.S. and southern Canada.

References

Thirteenth Ordinance on the Implementation of the Federal Immission Control Act (Ordinance on Large Combustion Plants and Gas Turbine Plants – 13. BImSchV)*)

Appendices

Appendix A – Capital and Operating Cost Forms

Appendix A

The tables on the following pages show the detailed calculation of the capital costs, the annualized costs (which includes operational expenses, maintenance expenses and the annualized capital cost) and the cost effectiveness of the control technologies.

Calculations were made at turbine sizes of 20 MW, 42 MW, 70 MW and 85 MW. For the latter three sizes, calculations were done for cases without supplemental firing, with supplemental firing to a temperature of 840 ℃, and with supplemental firing to a temperature of 1070 ℃. For the 20 MW case, the vendors advised that duct firing is not practical due to size limitations in the duct. Therefore a calculation was done for the case without supplemental firing only.

CAPITAL COST
SCR FOR 20MW COGEN SYSTEM WITHOUT DUCT BURNERS

Cost Item		Factor
Direct Costs		
Purchased Equipment Costs		
SCR + auxiliary equipment + 250,000 NH3 Storage =A [b]		$ 1,530,000
Catalyst = $430,000	(30% of SCR System)	$ -
Instrumentation (10 % of A)		$ 153,000
Sales taxes (3 % of A)		$ 45,900
Freight (5 % of A)		$ 76,500
Purchased equipment cost, PEC (B=1.18A)		$ 1,805,400
Direct installation costs		
Foundations & supports (8 % of PEC)		$ 144,432
Handling & erection (14 % of PEC)		$ 252,756
Electrical (4 % of PEC)		$ 72,216
Piping (2 % of PEC)		$ 36,108
Insulation for ductwork (1 % of PEC)		$ 18,054
Painting (1 % of PEC)		$ 18,054
Direct installation cost (0.30 B)		$ 541,620
Site preparation, as required		$ -
Buildings, as required		$ -
Total Direct Cost, DC		$ 2,347,020
Indirect Costs (installation)		
Engineering (10 % of PEC)		$ 180,540
Construction and field expenses (5 % of PEC)		$ 90,270
Contractor fees (10 % of PEC)		$ 180,540
Start-up (2 % of PEC)		$ 36,108
Performance test (1 % of PEC)		$ 18,054
Contingencies (3 % of PEC)		$ 54,162
Total Indirect Cost, IC		$ 559,674
Total Capital Investment, TIC = DC + IC (US Gulf Coast Cost)		$ 2,906,694
Cost Multiplier for Alberta (1.5)		1.5
Total Capital Investment Based on Alberta Costs		$ 4,360,041
Cost Multiplier for recent Jacobs Cost Est/EPA cost Est		$ 1.29
Total Capital Investment		$ 5,624,453

ANNUAL OPERATING COST
SCR SYSTEM FOR 20MW COGEN SYSTEM W/O DUCT BURNERS

Cost Item		Cost, $/Year
Total Capital Costs (TIC)	$	5,624,453
Direct Annual Costs, DAC [c]		
Operating labor		
Operator (1/2 hour per shift, @$25/hr)	$	13,688
Supervisor(15% of operator)	$	2,053
Operating materials		
Fuel (Natural Gas) @ $6.9/MMBtu, 0.085 MMBtu/hr, & 8,760 hrs/yr	$	5,138
Maintenance		
Labor (1/2 hour per shift)	$	13,688
Material (100% of maintenance labor)	$	13,688
Electricity		
(1.5 kW x 8760 hrs/yr x 0.0618/kW-hr)	$	812
Catalyst Replacement Cost (30% of Equipment Cost/5 year life)	$	86,000
NH3 Cost (9 # pure NH3/hr X $1000/ton X 8760 hours/year/2000 #/ton)	$	39,420
Direct Annual Cost (DAC)	$	174,485
Indirect Annual Costs, IAC		
Overhead (60 % of direct labor and maintenance)	$	25,869
Administrative charges (2 % of TIC)	$	112,489
Property tax (1 % of TIC)	$	56,245
Insurance (1 % of TIC)	$	56,245
Capital recovery [b]	$	657,102
Interest or long term bond rate, i = 0.08		
Capital Recovery cost factr = 0.117		
Indirect Annual Cost (IAC)	$	907,950
Total Annual Cost	$	1,082,435

a. Chapter 3: OAQPS Control Cost Manual, Sixth Edition

b. The capital recovery cost factor is based on 15 year equipment life and a 7 Jan 2010 Bank of Canada Bond rate
USEPA BACT Manual Appendix B equation for capital recovery factor = i*(1+i)^n/[(1+i)^n -1]

c. Operating materials, electricity, and waste disposal costs were estimated using engineering estimates.

SUMMARY OF BATEA ECONOMIC ANALYSIS
20 MW GAS TURBINE COGEN SYSTEM W/O DUCT BURNERS

Pollutant/ Emissions Unit	Control Alternative	Emissions (a) (lb/hr)	Emissions (a) (tpy)	Emissions Reduction (a) (tpy)	ECONOMIC IMPACT ANALYSIS: Total Annualized Cost (b) ($/yr)	ECONOMIC IMPACT ANALYSIS: Average Cost Effectiveness (c) ($/tonne)	ECONOMIC IMPACT ANALYSIS: Incremental Incremental Cost Effectiveness (d) ($/tonne)	ENVIRONMENTAL IMPACTS: Toxic Impacts (e) (Yes/No)	ENVIRONMENTAL IMPACTS: Adverse Environmental Impacts (f) (Yes/No)	ENERGY IMPACTS: Incremental Increase Over Baseline (g) (MMBtu/Yr)
Cogen NOx Reduction	Baseline NOx Emissions - Diffusion Burners	---	497							
	DLN Burners ($500,000 capital cost)(h)		79	418	$58,415	$140	$140	No	No	No
	Diffusion Burners + SCR		50	447	$1,082,435	$2,422	$35,311	No	Yes	Yes (745)
	DLN Burners + SCR		8	489	$1,140,850	$2,332	$15,203	No	Yes	Yes (745)
	The incremental cost of a DLN burner is < $10,000/ton. The incremental cost of adding an SCR to either a diffusion burner or a DLN burner is > $10,000/ton The cost effectiveness is based on an assumed 120 ppmv NOx in severe cold weather and 25 ppmv NOx the rest of the year for an annual average 27 ppmv NOx (j)									
	SCR cost/kWh = SCR annualized cost/8760 hours/yr/20,000 kW =				$0.00618					

(a) Emissions Reduction over baseline level. Emissions are shown in metric tonnes, not short tons.Emissions are based on 100% service factor

(b) Total Annualized Cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation)

(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.

(d) The Incremental Cost Effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives. In this case both SCR options are compared with the DLN option

(e) Toxics impact means there is a toxics impact consideration for the control alternative.

(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative. For the SCR cases 6.1 tonnes/yr NH_3 slip + NH_3 safety

(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btu's per year.

(h) DLN average cost based on 15 year life and long term bond rate

(i) NOx for diffusion burners based on 175 ppm. NOx for DLN burners based on GE LM2500 or Solar Titan both at 25 ppm. DLN1+ not currently available on these units.

(j) The USEPA uses a rough guideline for cost effectiveness of $10,000/ton emissions reduction. This number is adjusted up or down depending on whether the incremental technology has positive or negative other environmental impacts and whether the incremental technology has positive or negative impacts on energy consumption

SUMMARY OF BATEA ECONOMIC ANALYSIS
20 MW GAS TURBINE COGEN SYSTEM W/O DUCT BURNERS

20 MW	COMBINED CYCLE		SAGD - OTSG		STEAM RAISING (max)		STEAM RAISING (min)	
Commodity Factor	0.139	MWh / GJ	488	kg / GJ	440	kg / GJ	330	kg / GJ
FG Temp	100	°C	215	°C	115	°C	115	°C
GT Firing	199.7	GJ/h						
Duct Firing	0	GJ/h						
% Duct Firing	0%							
HRSG Output	107.1	GJ/h	79.6	GJ/h	103.5	GJ/h	103.5	GJ/h
Commodity Output	14.9	MW	39	tonne/h	46	tonne/h	34	tonne/h
GT Output	20	MW						
Incremental Cost for Control	$/kWh		$/kWh	$/tonne steam	$/kWh	$/tonne steam	$/kWh	$/tonne steam
DLN Burners ($500,000 capital cost)(h)	0.00019		0.00033	0.000	0.00033	0.000	0.00033	0.000
Diffusion Burners + SCR	0.00354		0.00618	0.000	0.00618	0.000	0.00618	0.000
DLN Burners + SCR	0.00373		0.00651	0.000	0.00651	0.000	0.00651	0.000

Cases

Combined Cycle – The steam generated at the HRSG drives a steam turbine to generate additional electricity. The flue gas stack temperature is assumed to be 100℃ (see section D), and the efficiency of conver ting the heat recovered at the HRSG to the electricity generated at the steam turbine, is assumed to be 50%.

SAGD – Steam is generated in a once-through steam generator. The flue gas stack temperature is assumed to be 215℃ (see section D). The boiler feedwater temperature is assumed to be 200℃, and the steam r aising pressure 11200 KPag.

Steam Raising (max) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

Steam Raising (min) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

The **Commodity Output** is the amount of commodity generated (electricity or steam) for each case.
The **Incremental Cost of Control** is calculated on a per commodity basis, taking the incremental costs for each control case from the BAT Cost Tables.
Where steam is generated in the SAGD and Steam Raising situations the control cost is allocated in part to each commodity by the ratio of the fuels fired at the gas

CAPITAL COST
SCR FOR 42MW COGEN SYSTEM WITHOUT DUCT BURNERS

Cost Item		Factor
Direct Costs		
Purchased Equipment Costs		
SCR + auxiliary equipment + 300,000 NH3 Storage =A [b]		$ 2,100,000
Catalyst = $630,000	(30% of SCR System)	$ -
Instrumentation (10 % of A)		$ 210,000
Sales taxes (3 % of A)		$ 63,000
Freight (5 % of A)		$ 105,000
Purchased equipment cost, PEC (B=1.18A)		$ 2,478,000
Direct installation costs		
Foundations & supports (8 % of PEC)		$ 198,240
Handling & erection (14 % of PEC)		$ 346,920
Electrical (4 % of PEC)		$ 99,120
Piping (2 % of PEC)		$ 49,560
Insulation for ductwork (1 % of PEC)		$ 24,780
Painting (1 % of PEC)		$ 24,780
Direct installation cost (0.30 B)		$ 743,400
Site preparation, as required		$ -
Buildings, as required		$ -
Total Direct Cost, DC		$ 3,221,400
Indirect Costs (installation)		
Engineering (10 % of PEC)		$ 247,800
Construction and field expenses (5 % of PEC)		$ 123,900
Contractor fees (10 % of PEC)		$ 247,800
Start-up (2 % of PEC)		$ 49,560
Performance test (1 % of PEC)		$ 24,780
Contingencies (3 % of PEC)		$ 74,340
Total Indirect Cost, IC		$ 768,180
Total Capital Investment, TIC = DC + IC		$ 3,989,580
Cost Multiplier for Alberta (1.5)		1.5
Total Capital Investment Based on Alberta Costs		$ 5,984,370
Cost Multiplier for recent Jacobs Cost Est/EPA cost Est		$ 1.29
Total Capital Investment		$ 7,719,837

ANNUAL OPERATING COST
SCR SYSTEM FOR 42MW COGEN SYSTEM WITHOUT DUCT BURNERS

Cost Item	Cost, $/Year
Total Capital Costs (TIC)	$ 7,719,837
Direct Annual Costs, DAC [c]	
Operating labor	
Operator (1/2 hour per shift, @$25/hr)	$ 13,688
Supervisor(15% of operator)	$ 2,053
Operating materials	
Fuel (Natural Gas) @ $6.9/MMBtu, 0.15 MMBtu/hr, & 8,760 hrs/yr	$ 9,067
Maintenance	
Labor (1/2 hour per shift)	$ 13,688
Material (100% of maintenance labor)	$ 13,688
Electricity	
(2.6 kW x 8760 hrs/yr x 0.0618/kW-hr)	$ 1,408
Catalyst Replacement Cost (30% of Equipment Cost/5 year life)	$ 126,000
NH3 Cost (16 # pure NH3/hr X $1000/ton X 8760 hours/year/2000 #/ton)	$ 70,080
Direct Annual Cost (DAC)	$ 249,670
Indirect Annual Costs, IAC	
Overhead (60 % of direct labor and maintenance)	$ 25,869
Administrative charges (2 % of TIC)	$ 154,397
Property tax (1 % of TIC)	$ 77,198
Insurance (1 % of TIC)	$ 77,198
Capital recovery [b]	$ 901,905
Interest or long term bond rate, i = 0.08	
Capital Recovery cost factr = 0.117	
Indirect Annual Cost (IAC)	$ 1,236,568
Total Annual Cost	$ 1,486,238

a. Chapter 3: OAQPS Control Cost Manual, Sixth Edition
b. The capital recovery cost factor is based on 15 year equipment life and a 7 Jan 2010 Bank of Canada Bond rate
USEPA BACT Manual Appendix B equation for capital recovery factor = i*(1+i)^n/[(1+i)^n -1]

SUMMARY OF BATEA ECONOMIC ANALYSIS
42 MW GAS TURBINE COGEN SYSTEM WITHOUT DUCT BURNERS

Pollutant/ Emissions Unit	Control Alternative	Emissions (a) (lb/hr)	Emissions (a) (tpy)	Emissions Reduction (a) (tpy)	ECONOMIC IMPACT ANALYSIS: Total Annualized Cost (b) ($/yr)	Average Cost Effectiveness (c) ($/tonne)	Incremental Incremental Cost Effectiveness (d) ($/tonne)	ENVIRONMENTAL IMPACTS: Toxic Impacts (e) (Yes/No)	Adverse Environmental Impacts (f) (Yes/No)	ENERGY IMPACTS: Incremental Increase Over Baseline (g) (MMBtu/Yr)
Cogen NOx Reduction	Baseline NOx Emissions - Diffusion Burners + duct burners	---	1154							
	DLN Burners ($0.7 MM capital cost)		134	1020.0	$81,781	$80	$80	No	No	No
	Diffusion Burners + SCR		115	1039.0	$1,486,238	$1,430	$73,919	No	Yes	Yes (1300)
	DLN Burners + SCR		13	1141.0	$1,568,018	$1,374	$12,283	No	Yes	Yes (1300)
	Based on the above DLN burners have a cost effectiveness < $10,000/ton. Adding an SCR to a DLN burner has a cost effectiveness slightly above $10,000/ton. Going to a diffusion burner + SCR verus a DLN burner has a cost effectiveness > $10,000/ton. Cost effectiveness is based on an assumed 20 ppm NOx in the turbine exhaust (j)									
	SCR cost/kWh = SCR annualized cost/8760 hours/yr/42,000 kW =				$0.00404					

(a) Emissions Reduction over baseline level. Emissions are shown in metric tonnes, not short tons. Emissions are based on 100% service factor

(b) Total Annualized Cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation)

(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.

(d) The Incremental Cost Effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives. In this case both SCR cases are compared to the DLN case

(e) Toxics impact means there is a toxics impact consideration for the control alternative.

(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative. For the SCR cases the NH3 slip is 12 tonnes/yr + NH3 safety concerns

(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btu's per year.

(h) DLN average cost based on 15 year life and long term bond rate

(i) The DLN NOx estimate NOx emissions of 20 ppmv are based on a GE 6B gas turbine.
A Siemens SGT800 is guaranteed for 15 ppmv. GE does not offer a DLN1+ burner for this turbine
At 15 ppm the SCR would not be cost effective versus DLN ($12,500/ton).

(j) The USEPA uses a rough guideline for cost effectiveness of $10,000/ton emissions reduction. This number is adjusted up or down depending on whether the incremental technology has positive or negative other environmental impacts and whether the incremental technology has positive or negative impacts on energy consumption

SUMMARY OF BATEA ECONOMIC ANALYSIS
42 MW GAS TURBINE COGEN SYSTEM WITHOUT DUCT BURNERS

42.1 MW	COMBINED CYCLE		SAGD - OTSG		STEAM RAISING (max)		STEAM RAISING (min)	
Commodity Factor	0.139	MWh / GJ	488	kg / GJ	440	kg / GJ	330	kg / GJ
FG Temp	100	°C	215	°C	115	°C	115	°C
GT Firing	472.8	GJ/h						
Duct Firing	0	GJ/h						
% Duct Firing	0%							
HRSG Output	254.8	GJ/h	191.6	GJ/h	246.6	GJ/h	246.6	GJ/h
Commodity Output	35.4	MW	94	tonne/h	108	tonne/h	81	tonne/h
GT Output	42.1	MW						
Incremental Cost for Control	$/kWh		$/kWh	$/tonne steam	$/kWh	$/tonne steam	$/kWh	$/tonne steam
DLN Burners ($0.7 MM capital cost)	0.00012		0.00022	0.000	0.00022	0.000	0.00022	0.000
Diffusion Burners + SCR	0.00219		0.00403	0.000	0.00403	0.000	0.00403	0.000
DLN Burners + SCR	0.00231		0.00425	0.000	0.00425	0.000	0.00425	0.000

Cases

Combined Cycle – The steam generated at the HRSG drives a steam turbine to generate additional electricity. The flue gas stack temperature is assumed to be 100℃ (see section D), and the efficiency of conver ting the heat recovered at the HRSG to the electricity generated at the steam turbine, is assumed to be 50%.

SAGD – Steam is generated in a once-through steam generator. The flue gas stack temperature is assumed to be 215℃ (see section D). The boiler feedwater temperature is assumed to be 200℃, and the steam r aising pressure 11200 KPag.

Steam Raising (max) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

Steam Raising (min) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

The **Commodity Output** is the amount of commodity generated (electricity or steam) for each case.
The **Incremental Cost of Control** is calculated on a per commodity basis, taking the incremental costs for each control case from the BAT Cost Tables.
Where steam is generated in the SAGD and Steam Raising situations the control cost is allocated in part to each commodity by the ratio of the fuels fired at the gas turbine and HRSG. For example, if 70% of the fuel is fired in the gas turbine, then 70% of the control cost is assigned to the electricity generated at the gas turbine.

CAPITAL COST
SCR FOR 42MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

Cost Item	Factor
Direct Costs	
Purchased Equipment Costs	
SCR + auxiliary equipment + 300,000 NH3 Storage =A [b]	$ 2,200,000
Catalyst = $650,000 (30% of SCR System)	$ -
Instrumentation (10 % of A)	$ 220,000
Sales taxes (3 % of A)	$ 66,000
Freight (5 % of A)	$ 110,000
Purchased equipment cost, PEC (B=1.18A)	$ 2,596,000
Direct installation costs	
Foundations & supports (8 % of PEC)	$ 207,680
Handling & erection (14 % of PEC)	$ 363,440
Electrical (4 % of PEC)	$ 103,840
Piping (2 % of PEC)	$ 51,920
Insulation for ductwork (1 % of PEC)	$ 25,960
Painting (1 % of PEC)	$ 25,960
Direct installation cost (0.30 B)	$ 778,800
Site preparation, as required	$ -
Buildings, as required	$ -
Total Direct Cost, DC	$ 3,374,800
Indirect Costs (installation)	
Engineering (10 % of PEC)	$ 259,600
Construction and field expenses (5 % of PEC)	$ 129,800
Contractor fees (10 % of PEC)	$ 259,600
Start-up (2 % of PEC)	$ 51,920
Performance test (1 % of PEC)	$ 25,960
Contingencies (3 % of PEC)	$ 77,880
Total Indirect Cost, IC	$ 804,760
Total Capital Investment, TIC = DC + IC	$ 4,179,560
Cost Multiplier for Alberta (1.5)	1.5
Total Capital Investment Based on Alberta Costs	$ 6,269,340
Cost Multiplier for recent Jacobs Cost Est/EPA cost Est	$ 1.29
Total Capital Investment	$ 8,087,449

ANNUAL OPERATING COST
SCR SYSTEM FOR 42MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

Cost Item	Cost, $/Year
Total Capital Costs (TIC)	$ 8,087,449
<u>Direct Annual Costs, DAC [c]</u>	
Operating labor	
Operator (1/2 hour per shift, @$25/hr)	$ 13,688
Supervisor(15% of operator)	$ 2,053
Operating materials	
Fuel (Natural Gas) @ $6.9/MMBtu, 0.20 MMBtu/hr, & 8,760 hrs/yr	$ 12,089
Maintenance	
Labor (1/2 hour per shift)	$ 13,688
Material (100% of maintenance labor)	$ 13,688
Electricity	
(3.6 kW x 8760 hrs/yr x 0.0618/kW-hr)	$ 1,949
Catalyst Replacement Cost (30% of Equipment Cost/5 year life)	$ 130,000
NH3 Cost (22 # pure NH3/hr X $1000/ton X 8760 hours/year/2000 #/ton)	$ 96,360
Direct Annual Cost (DAC)	$ 283,513
Indirect Annual Costs, IAC	
Overhead (60 % of direct labor and maintenance)	$ 25,869
Administrative charges (2 % of TIC)	$ 161,749
Property tax (1 % of TIC)	$ 80,874
Insurance (1 % of TIC)	$ 80,874
Capital recovery [b]	$ 944,853
Interest or long term bond rate, i = 0.08	
Capital Recovery cost factr = 0.117	
Indirect Annual Cost (IAC)	$ 1,294,220
Total Annual Cost	$ 1,577,734

a. Chapter 3: OAQPS Control Cost Manual, Sixth Edition
b. The capital recovery cost factor is based on 15 year equipment life and a 7 Jan 2010 Bank of Canada Bond rate
USEPA BACT Manual Appendix B equation for capital recovery factor = i*(1+i)^n/[(1+i)^n -1]

SUMMARY OF BATEA ECONOMIC ANALYSIS
42 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

Pollutant/ Emissions Unit	Control Alternative	Emissions (a)		Emissions Reduction (a)	ECONOMIC IMPACT ANALYSIS			ENVIRONMENTAL IMPACTS		ENERGY IMPACTS
		(lb/hr)	(tpy)	(tpy)	Total Annualized Cost (b) ($/yr)	Average Cost Effectiveness (c) ($/tonne)	Incremental Incremental Cost Effectiveness (d) ($/tonne)	Toxic Impacts (e) (Yes/No)	Adverse Environmental Impacts (f) (Yes/No)	Incremental Increase Over Baseline (g) (MMBtu/Yr)
Cogen NOx Reduction	Baseline NOx Emissions - Diffusion Burners + duct burners	---	1224							
	DLN Burners ($0.7 MM capital cost)(h)		204	1020.0	$81,781	$80	$80	No	No	No
	Diffusion Burners + SCR		122	1102.0	$1,577,734	$1,432	$18,243	No	Yes	Yes (1800)
	DLN Burners + SCR		20	1204.0	$1,659,514	$1,378	$8,575	No	Yes	Yes (1800)
	Based on the above DLN burners have a cost effectiveness < $10,000/ton. Adding an SCR to a DLN burner has a cost effectiveness < $10,000/ton. Going to a diffusion burner + SCR verus a DLN burner has a cost effectiveness > $10,000/ton. Cost effectiveness									
	SCR cost/kWh = SCR annualized cost/8760 hours/yr/42,000 kW =				$0.00429					

(a) Emissions Reduction over baseline level. Emissions are shown in metric tonnes, not short tons. Emissions are based on 100% service factor

(b) Total Annualized Cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation)

(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.

(d) The Incremental Cost Effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives. In this case both

(e) Toxics impact means there is a toxics impact consideration for the control alternative.

(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative. For the SCR cases the NH3 slip is 12 tonnes/yr + NH3 safety concerns

(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btu's per year.

(h) DLN average cost based on 15 year life and long term bond rate

(i) The DLN NOx estimate NOx emissions of 20 ppmv are based on a GE 6B gas turbine interpolted to 70 MW.
A Siemens SGT800 is guaranteed for 15 ppmv. A DLN1+ is not available on this gas turbine
At 15 ppm the SCR would still be incrementally cost effective versus DLN ($8,500/ton).

(j) Assumed a Low NOx duct burner with a NOx emission factor of 38 g/GJ. The alternate is the new Dual Recirculaton duct burner with an emission factor of 22 g/GJ.
Adding an SCR would still be incrementally cost effective ($8400/ton) with a Dual Recirculation Duct Burner.

(k) The USEPA uses a rough guideline for cost effectiveness of $10,000/ton emissions reduction. This number is adjusted up or down depending on whether the incremental technology has positive or negative other environmental impacts and whether the incremental technology has positive or negative impacts on energy consumption

SUMMARY OF BATEA ECONOMIC ANALYSIS
42 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

42.1 MW	COMBINED CYCLE		SAGD - OTSG		STEAM RAISING (max)		STEAM RAISING (min)	
Commodity Factor	0.139	MWh / GJ	488	kg / GJ	440	kg / GJ	330	kg / GJ
FG Temp	100	°C	215	°C	115	°C	115	°C
GT Firing	472.8	GJ/h						
Duct Firing	389.7	GJ/h						
% Duct Firing	43%							
HRSG Output	605.9	GJ/h	540.1	GJ/h	597.3	GJ/h	597.3	GJ/h
Commodity Output	84.2	MW	264	tonne/h	263	tonne/h	197	tonne/h
GT Output	42.1	MW						
Incremental Cost for Control	$/kWh		$/kWh	$/tonne steam	$/kWh	$/tonne steam	$/kWh	$/tonne steam
DLN Burners ($0.7 MM capital cost)(h)	0.00007		0.00013	0.015	0.00013	0.015	0.00013	0.020
Diffusion Burners + SCR	0.00143		0.00245	0.292	0.00245	0.293	0.00245	0.391
DLN Burners + SCR	0.00150		0.00257	0.308	0.00257	0.309	0.00257	0.411

Cases

Combined Cycle – The steam generated at the HRSG drives a steam turbine to generate additional electricity. The flue gas stack temperature is assumed to be 100℃ (see section D), and the efficiency of conver ting the heat recovered at the HRSG to the electricity generated at the steam turbine, is assumed to be 50%.

SAGD – Steam is generated in a once-th `
temperature is assumed to be 200℃, and the steam r aising pressure 11200 KPag.

Steam Raising (max) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

Steam Raising (min) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

The **Commodity Output** is the amount of commodity generated (electricity or steam) for each case.
The **Incremental Cost of Control** is calculated on a per commodity basis, taking the incremental costs for each control case from the BAT Cost Tables.
Where steam is generated in the SAGD and Steam Raising situations the control cost is allocated in part to each commodity by the ratio of the fuels fired at the gas turbine and HRSG. For example, if 70% of the fuel is fired in the gas turbine, then 70% of the control cost is assigned to the electricity generated at the gas turbine. The remaining 30% of the control cost is assigned to the steam generated in the HRSG.

CAPITAL COST
SCR FOR 42MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

Cost Item			Factor
Direct Costs			
Purchased Equipment Costs			
SCR + auxiliary equipment + 300,000 NH3 Storage =A [b]			$ 2,200,000
Catalyst = $650,000	(30% of SCR System)		$ -
Instrumentation (10 % of A)			$ 220,000
Sales taxes (3 % of A)			$ 66,000
Freight (5 % of A)			$ 110,000
Purchased equipment cost, PEC (B=1.18A)			$ 2,596,000
Direct installation costs			
Foundations & supports (8 % of PEC)			$ 207,680
Handling & erection (14 % of PEC)			$ 363,440
Electrical (4 % of PEC)			$ 103,840
Piping (2 % of PEC)			$ 51,920
Insulation for ductwork (1 % of PEC)			$ 25,960
Painting (1 % of PEC)			$ 25,960
Direct installation cost (0.30 B)			$ 778,800
Site preparation, as required			$ -
Buildings, as required			$ -
Total Direct Cost, DC			$ 3,374,800
Indirect Costs (installation)			
Engineering (10 % of PEC)			$ 259,600
Construction and field expenses (5 % of PEC)			$ 129,800
Contractor fees (10 % of PEC)			$ 259,600
Start-up (2 % of PEC)			$ 51,920
Performance test (1 % of PEC)			$ 25,960
Contingencies (3 % of PEC)			$ 77,880
Total Indirect Cost, IC			$ 804,760
Total Capital Investment, TIC = DC + IC			$ 4,179,560
Cost Multiplier for Alberta (1.5)			1.5
Total Capital Investment Based on Alberta Costs			$ 6,269,340
Cost Multiplier for recent Jacobs Cost Est/EPA cost Est			$ 1.29
Total Capital Investment			$ 8,087,449

ANNUAL OPERATING COST
SCR SYSTEM FOR 42MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

Cost Item		Cost, $/Year
Total Capital Costs (TIC)		$ 8,087,449
Direct Annual Costs, DAC [c]		
Operating labor		
Operator (1/2 hour per shift, @$25/hr)		$ 13,688
Supervisor(15% of operator)		$ 2,053
Operating materials		
Fuel (Natural Gas) @ $6.9/MMBtu, 0.27 MMBtu/hr, & 8,760 hrs/yr		$ 16,320
Maintenance		
Labor (1/2 hour per shift)		$ 13,688
Material (100% of maintenance labor)		$ 13,688
Electricity		
(4.6 kW x 8760 hrs/yr x 0.0618/kW-hr)		$ 2,490
Catalyst Replacement Cost (30% of Equipment Cost/5 year life)		$ 130,000
NH3 Cost (28 # pure NH3/hr X $1000/ton X 8760 hours/year/2000 #/ton)		$ 122,640
Direct Annual Cost (DAC)		$ 314,566
Indirect Annual Costs, IAC		
Overhead (60 % of direct labor and maintenance)		$ 25,869
Administrative charges (2 % of TIC)		$ 161,749
Property tax (1 % of TIC)		$ 80,874
Insurance (1 % of TIC)		$ 80,874
Capital recovery [b]		$ 944,853
Interest or long term bond rate, i =	0.08	
Capital Recovery cost factr =	0.117	
Indirect Annual Cost (IAC)		$ 1,294,220
Total Annual Cost		$ 1,608,786

a. Chapter 3: OAQPS Control Cost Manual, Sixth Edition

b. The capital recovery cost factor is based on 15 year equipment life and a 7 Jan 2010 Bank of Canada Bond rate
USEPA BACT Manual Appendix B equation for capital recovery factor = i*(1+i)^n/[(1+i)^n -1]

SUMMARY OF BATEA ECONOMIC ANALYSIS
42 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

Pollutant/ Emissions Unit	Control Alternative	Emissions (a) (lb/hr)	Emissions (a) (tpy)	Emissions Reduction (a) (tpy)	ECONOMIC IMPACT ANALYSIS: Total Annualized Cost (b) ($/yr)	ECONOMIC IMPACT ANALYSIS: Average Cost Effectiveness (c) ($/tonne)	ECONOMIC IMPACT ANALYSIS: Incremental Incremental Cost Effectiveness (d) ($/tonne)	ENVIRONMENTAL IMPACTS: Toxic Impacts (e) (Yes/No)	ENVIRONMENTAL IMPACTS: Adverse Environmental Impacts (f) (Yes/No)	ENERGY IMPACTS: Incremental Increase Over Baseline (g) (MMBtu/Yr)
Cogen NOx Reduction	Baseline NOx Emissions - Diffusion Burners + duct burners	---	1284							
	DLN Burners ($0.7 MM capital cost)(h)		264	1020.0	$81,781	$80	$80	No	No	No
	Diffusion Burners + SCR		128	1156.0	$1,608,786	$1,392	$11,228	No	Yes	Yes (2300)
	DLN Burners + SCR		26	1258.0	$1,690,567	$1,344	$6,760	No	Yes	Yes (2300)
	Based on the above DLN burners have a cost effectiveness < $10,000/ton. Adding an SCR to a DLN burner has a cost effectiveness < $10,000/ton. Going to a diffusion burner + SCR verus a DLN burner has a cost effectiveness > $10,000/ton. Cost effectiveness is based on an assumed 20 pmv NOx in the turbine exhaust (k)									
	SCR cost/kWh = SCR annualized cost/8760 hours/yr/42,000 kW =				$0.00437					

(a) Emissions Reduction over baseline level. Emissions are shown in metric tonnes, not short tons. Emissions are based on 100% service factor

(b) Total Annualized Cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation)

(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.

(d) The Incremental Cost Effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives. In this case both SCR cases are compared with the DLN case

(e) Toxics impact means there is a toxics impact consideration for the control alternative.

(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative. For the SCR cases the NH3 slip is 12 tonnes/yr + NH3 safety concerns

(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btu's per year.

(h) DLN average cost based on 15 year life and long term bond rate

(i) The DLN NOx estimate NOx emissions of 20 ppmv are based on a GE 6B gas turbine interpolted to 70 MW.
A Siemens SGT800 is guaranteed for 15 ppmv. A DLN1+ is not available on this gas turbine
At 15 ppm the SCR would still be incrementally cost effective versus DLN ($8,500/ton).

(j) Assumed a Low NOx duct burner with a NOx emission factor of 38 g/GJ. The alternate is the new Dual Recirculaton duct burner with an emission factor of 22 g/GJ.
Adding an SCR would still be incrementally cost effective ($8400/ton) with a Dual Recirculation Duct Burner.

(k) The USEPA uses a rough guideline for cost effectiveness of $10,000/ton emissions reduction. This number is adjusted up or down depending on whether the incremental technology has positive or negative other environmental impacts and whether the incremental technology has positive or negative impacts on energy consumption

SUMMARY OF BATEA ECONOMIC ANALYSIS
42 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

42.1 MW	COMBINED CYCLE		SAGD - OTSG		STEAM RAISING (max)		STEAM RAISING (min)	
Commodity Factor	0.139	MWh / GJ	488	kg / GJ	440	kg / GJ	330	kg / GJ
FG Temp	100	°C	215	°C	115	°C	115	°C
GT Firing	472.8	GJ/h						
Duct Firing	389.7	GJ/h						
% Duct Firing	43%							
HRSG Output	605.9	GJ/h	540.1	GJ/h	597.3	GJ/h	597.3	GJ/h
Commodity Output	84.2	MW	264	tonne/h	263	tonne/h	197	tonne/h
GT Output	42.1	MW						
Incremental Cost for Control	$/kWh		$/kWh	$/tonne steam	$/kWh	$/tonne steam	$/kWh	$/tonne steam
DLN Burners ($0.7 MM capital cost)(h)	0.00007		0.00013	0.015	0.00013	0.015	0.00013	0.020
Diffusion Burners + SCR	0.00145		0.00250	0.298	0.00250	0.299	0.00250	0.399
DLN Burners + SCR	0.00153		0.00262	0.313	0.00262	0.314	0.00262	0.419

Cases

Combined Cycle – The steam generated at the HRSG drives a steam turbine to generate additional electricity. The flue gas stack temperature is assumed to be 100℃ (see section D), and the efficiency of conver ting the heat recovered at the HRSG to the electricity generated at the steam turbine, is assumed to be 50%.

SAGD – Steam is generated in a once-th `
temperature is assumed to be 200℃, and the steam r aising pressure 11200 KPag.

Steam Raising (max) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

Steam Raising (min) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

The **Commodity Output** is the amount of commodity generated (electricity or steam) for each case.
The **Incremental Cost of Control** is calculated on a per commodity basis, taking the incremental costs for each control case from the BAT Cost Tables.
Where steam is generated in the SAGD and Steam Raising situations the control cost is allocated in part to each commodity by the ratio of the fuels fired at the gas turbine and HRSG. For example, if 70% of the fuel is fired in the gas turbine, then 70% of the control cost is assigned to the electricity generated at the gas turbine. The remaining 30% of the control cost is assigned to the steam generated in the HRSG.

CAPITAL COST
SCR FOR 70MW COGEN SYSTEM WITHOUT DUCT BURNERS

Cost Item	Factor
Direct Costs	
Purchased Equipment Costs	
SCR + auxiliary equipment + 300,000 NH3 Storage =A [b]	$ 2,850,000
Catalyst = $850,000 (30% of SCR System)	$ -
Instrumentation (10 % of A)	$ 285,000
Sales taxes (3 % of A)	$ 85,500
Freight (5 % of A)	$ 142,500
Purchased equipment cost, PEC (B=1.18A)	$ 3,363,000
Direct installation costs	
Foundations & supports (8 % of PEC)	$ 269,040
Handling & erection (14 % of PEC)	$ 470,820
Electrical (4 % of PEC)	$ 134,520
Piping (2 % of PEC)	$ 67,260
Insulation for ductwork (1 % of PEC)	$ 33,630
Painting (1 % of PEC)	$ 33,630
Direct installation cost (0.30 B)	$ 1,008,900
Site preparation, as required	$ -
Buildings, as required	$ -
Total Direct Cost, DC	$ 4,371,900
Indirect Costs (installation)	
Engineering (10 % of PEC)	$ 336,300
Construction and field expenses (5 % of PEC)	$ 168,150
Contractor fees (10 % of PEC)	$ 336,300
Start-up (2 % of PEC)	$ 67,260
Performance test (1 % of PEC)	$ 33,630
Contingencies (3 % of PEC)	$ 100,890
Total Indirect Cost, IC	$ 1,042,530
Total Capital Investment, TIC = DC + IC	$ 5,414,430
Cost Multiplier for Alberta (1.5)	1.5
Total Capital Investment Based on Alberta Costs	$ 8,121,645
Cost Multiplier for recent Jacobs Cost Est/EPA cost Est	$ 1.29
Total Capital Investment	$ 10,476,922

ANNUAL OPERATING COST
SCR SYSTEM FOR 70MW COGEN SYSTEM WITHOUT DUCT BURNERS

Cost Item	Cost, $/Year
Total Capital Costs (TIC)	$ 10,476,922
Direct Annual Costs, DAC [c]	
Operating labor	
Operator (1/2 hour per shift, @$25/hr)	$ 13,688
Supervisor(15% of operator)	$ 2,053
Operating materials	
Fuel (Natural Gas) @ $6.9/MMBtu, 0.24 MMBtu/hr, & 8,760 hrs/yr	$ 14,507
Maintenance	
Labor (1/2 hour per shift)	$ 13,688
Material (100% of maintenance labor)	$ 13,688
Electricity	
(4.3 kW x 8760 hrs/yr x 0.0618/kW-hr)	$ 2,328
Catalyst Replacement Cost (30% of Equipment Cost/5 year life)	$ 170,000
NH3 Cost (26 # pure NH3/hr X $1000/ton X 8760 hours/year/2000 #/ton)	$ 113,880
Direct Annual Cost (DAC)	$ 343,830
Indirect Annual Costs, IAC	
Overhead (60 % of direct labor and maintenance)	$ 25,869
Administrative charges (2 % of TIC)	$ 209,538
Property tax (1 % of TIC)	$ 104,769
Insurance (1 % of TIC)	$ 104,769
Capital recovery [b]	$ 1,224,014
Interest or long term bond rate, i = 0.08	
Capital Recovery cost factr = 0.117	
Indirect Annual Cost (IAC)	$ 1,668,960
Total Annual Cost	$ 2,012,790

a. Chapter 3: OAQPS Control Cost Manual, Sixth Edition

b. The capital recovery cost factor is based on 15 year equipment life and a 7 Jan 2010 Bank of Canada Bond rate
USEPA BACT Manual Appendix B equation for capital recovery factor = i*(1+i)^n/[(1+i)^n -1]

SUMMARY OF BATEA ECONOMIC ANALYSIS
70 MW GAS TURBINE COGEN SYSTEM WITHOUT DUCT BURNERS

Pollutant/ Emissions Unit	Control Alternative	Emissions (a)		Emissions Reduction (a)	ECONOMIC IMPACT ANALYSIS			ENVIRONMENTAL IMPACTS		ENERGY IMPACTS
		(lb/hr)	(tpy)	(tpy)	Total Annualized Cost (b) ($/yr)	Average Cost Effectiveness (c) ($/tonne)	Incremental Incremental Cost Effectiveness (d) ($/tonne)	Toxic Impacts (e) (Yes/No)	Adverse Environmental Impacts (f) (Yes/No)	Incremental Increase Over Baseline (g) (MMBtu/Yr)
Cogen NOx Reduction	Baseline NOx Emissions - Diffusion Burners + duct burners	---	1920							
	DLN Burners ($1.0 MM capital cost)		226	1694.0	$116,830	$69	$69	No	No	No
	Diffusion Burners + SCR		192	1728.0	$2,012,790	$1,165	$55,764	No	Yes	Yes (2100)
	DLN Burners + SCR		23	1897.0	$2,129,620	$1,123	$9,915	No	Yes	Yes (2100)
	Based on the above DLN burners have a cost effectiveness of < $10,000/ton. Adding an SCR to a DLN burner has a cost effectiveness < $10,000/ton. Going to a diffusion burner + SCR verus a DLN burner has a cost effectiveness > $10,000/ton. Cost effectiveness is based on an assumed 20 ppmv NOx in the turbine exhaust.(j)									
	SCR cost/kWh = SCR annualized cost/8760 hours/yr/70,000 kW =				$0.00328					

(a) Emissions Reduction over baseline level. Emissions are shown in metric tonnes, not short tons. Emissions are based on 100% service factor

(b) Total Annualized Cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation)

(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.

(d) The Incremental Cost Effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives. In this case both SCR options were compared with the DLN burner case

(e) Toxics impact means there is a toxics impact consideration for the control alternative.

(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative. For the SCR cases the NH3 slip is 22 tonnes/yr + NH3 safety concerns

(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btu's per year.

(h) DLN average cost based on 15 year life and long term bond rate

(i) The DLN NOx estimate NOx emissions of 20 ppmv are based on a GE 7EA gas turbine interpolted to 70 MW.
A Siemens SGT800 is guaranteed for 15 ppmv and the new GE DLN1+ is guaranteed for 9 ppmv below - 12C and 5 ppmv above -12C
At 15 ppm the SCR would be marginally not cost effective versus DLN ($10,800/ton). An SCR would not be cost effective versus a DLN1+

(j) The USEPA uses a rough guideline for cost effectiveness of $10,000/ton emissions reduction. This number is adjusted up or down depending on whether the incremental technology has positive or negative other environmental impacts and whether the incremental technology has positive or negative impacts on energy consumption

SUMMARY OF BATEA ECONOMIC ANALYSIS
70 MW GAS TURBINE COGEN SYSTEM WITHOUT DUCT BURNERS

70 MW	COMBINED CYCLE		SAGD - OTSG		STEAM RAISING (max)		STEAM RAISING (min)	
Commodity Factor	0.139	MWh / GJ	488	kg / GJ	440	kg / GJ	330	kg / GJ
FG Temp	100	°C	215	°C	115	°C	115	°C
GT Firing	770	GJ/h						
Duct Firing	0	GJ/h						
% Duct Firing	0%							
HRSG Output	417.4	GJ/h	311.2	GJ/h	403.5	GJ/h	403.5	GJ/h
Commodity Output	58.0	MW	152	tonne/h	178	tonne/h	133	tonne/h
GT Output	70	MW						
Incremental Cost for Control	$/kWh		$/kWh	$/tonne steam	$/kWh	$/tonne steam	$/kWh	$/tonne steam
DLN Burners ($1.0 MM capital cost)	0.00010		0.00019	0.000	0.00019	0.000	0.00019	0.000
Diffusion Burners + SCR	0.00180		0.00328	0.000	0.00328	0.000	0.00328	0.000
DLN Burners + SCR	0.00190		0.00347	0.000	0.00347	0.000	0.00347	0.000

Cases

Combined Cycle – The steam generated at the HRSG drives a steam turbine to generate additional electricity. The flue gas stack temperature is assumed to be 100°C (see section D), and the efficiency of converting the heat recovered at the HRSG to the electricity generated at the steam turbine, is assumed to be 50%.

SAGD – Steam is generated in a once-through steam generator. The flue gas stack temperature is assumed to be 215°C (see section D). The boiler feedwater temperature is assumed to be 200°C, and the steam raising pressure 11200 KPag.

Steam Raising (max) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115°C, for a boiler feedwater temperature of 100°C. This case represents the maximum steam raising capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

Steam Raising (min) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115°C, for a boiler feedwater temperature of 100°C. This case represents the maximum steam raising capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

The **Commodity Output** is the amount of commodity generated (electricity or steam) for each case.
The **Incremental Cost of Control** is calculated on a per commodity basis, taking the incremental costs for each control case from the BAT Cost Tables.
Where steam is generated in the SAGD and Steam Raising situations the control cost is allocated in part to each commodity by the ratio of the fuels fired at the gas turbine and HRSG. For example, if 70% of the fuel is fired in the gas turbine, then 70% of the control cost is assigned to the electricity generated at the gas turbine. The remaining 30% of the control cost is assigned to the steam generated in the HRSG.

CAPITAL COST

SCR FOR 70MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

Cost Item	Factor
Direct Costs	
Purchased Equipment Costs	
SCR + auxiliary equipment + 300,000 NH3 Storage =A [b]	$ 2,950,000
Catalyst = $880,000 (30% of SCR System)	$ -
Instrumentation (10 % of A)	$ 295,000
Sales taxes (3 % of A)	$ 88,500
Freight (5 % of A)	$ 147,500
Purchased equipment cost, PEC (B=1.18A)	$ 3,481,000
Direct installation costs	
Foundations & supports (8 % of PEC)	$ 278,480
Handling & erection (14 % of PEC)	$ 487,340
Electrical (4 % of PEC)	$ 139,240
Piping (2 % of PEC)	$ 69,620
Insulation for ductwork (1 % of PEC)	$ 34,810
Painting (1 % of PEC)	$ 34,810
Direct installation cost (0.30 B)	$ 1,044,300
Site preparation, as required	$ -
Buildings, as required	$ -
Total Direct Cost, DC	$ 4,525,300
Indirect Costs (installation)	
Engineering (10 % of PEC)	$ 348,100
Construction and field expenses (5 % of PEC)	$ 174,050
Contractor fees (10 % of PEC)	$ 348,100
Start-up (2 % of PEC)	$ 69,620
Performance test (1 % of PEC)	$ 34,810
Contingencies (3 % of PEC)	$ 104,430
Total Indirect Cost, IC	$ 1,079,110
Total Capital Investment, TIC = DC + IC	$ 5,604,410
Cost Multiplier for Alberta (1.5)	1.5
Total Capital Investment Based on Alberta Costs	$ 8,406,615
Cost Multiplier for recent Jacobs Cost Est/EPA cost Est	$ 1.29
Total Capital Investment	$ 10,844,533

ANNUAL OPERATING COST
SCR SYSTEM FOR 70MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

Cost Item		Cost, $/Year
Total Capital Costs (TIC)	$	10,844,533
Direct Annual Costs, DAC [c]		
Operating labor		
Operator (1/2 hour per shift, @$25/hr)	$	13,688
Supervisor(15% of operator)	$	2,053
Operating materials		
Fuel (Natural Gas) @ $6.9/MMBtu, 0.36 MMBtu/hr, & 8,760 hrs/yr	$	21,760
Maintenance		
Labor (1/2 hour per shift)	$	13,688
Material (100% of maintenance labor)	$	13,688
Electricity		
(6.3 kW x 8760 hrs/yr x 0.0618/kW-hr)	$	3,411
Catalyst Replacement Cost (30% of Equipment Cost/5 year life)	$	176,000
NH3 Cost (38 # pure NH3/hr X $1000/ton X 8760 hours/year/2000 #/ton)	$	166,440
Direct Annual Cost (DAC)	$	410,726
Indirect Annual Costs, IAC		
Overhead (60 % of direct labor and maintenance)	$	25,869
Administrative charges (2 % of TIC)	$	216,891
Property tax (1 % of TIC)	$	108,445
Insurance (1 % of TIC)	$	108,445
Capital recovery [b]	$	1,266,962
Interest or long term bond rate, i = 0.08		
Capital Recovery cost factr = 0.117		
Indirect Annual Cost (IAC)	$	1,726,613
Total Annual Cost	$	2,137,339

a. Chapter 3: OAQPS Control Cost Manual, Sixth Edition
b. The capital recovery cost factor is based on 15 year equipment life and a 7 Jan 2010 Bank of Canada Bond rate
USEPA BACT Manual Appendix B equation for capital recovery factor = i*(1+i)^n/[(1+i)^n -1]

SUMMARY OF BATEA ECONOMIC ANALYSIS
70 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

Pollutant/ Emissions Unit	Control Alternative	Emissions (a) (lb/hr)	Emissions (a) (tpy)	Emissions Reduction (a) (tpy)	ECONOMIC IMPACT ANALYSIS: Total Annualized Cost (b) ($/yr)	Average Cost Effectiveness (c) ($/tonne)	Incremental Incremental Cost Effectiveness (d) ($/tonne)	ENVIRONMENTAL IMPACTS: Toxic Impacts (e) (Yes/No)	Adverse Environmental Impacts (f) (Yes/No)	ENERGY IMPACTS: Incremental Increase Over Baseline (g) (MMBtu/Yr)
Cogen NOx Reduction	Baseline NOx Emissions - Diffusion Burners + duct burners	---	2042							
	DLN Burners ($1.0 MM capital cost)(h)		348	1694.0	$116,830	$69	$69	No	No	No
	Diffusion Burners + SCR		204	1838.0	$2,137,339	$1,163	$14,031	No	Yes	Yes (3200)
	DLN Burners + SCR		35	2007.0	$2,254,168	$1,123	$6,829	No	Yes	Yes (3200)
	Based on the above DLN burners have a cost effectiveness < $10,000/ton. Adding an SCR to a DLN burner has a cost effectiveness < $10,000/ton. Going to a diffusion burner + SCR verus a DLN burner has a cost effectiveness < $10,000/ton. Cost effectiveness									
	SCR cost/kWh = SCR annualized cost/8760 hours/yr/70,000 kW =				$0.00349					

(a) Emissions Reduction over baseline level. Emissions are shown in metric tonnes, not short tons. Emissions are based on 100% service factor

(b) Total Annualized Cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation)

(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.

(d) The Incremental Cost Effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives. In this case the

(e) Toxics impact means there is a toxics impact consideration for the control alternative.

(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative. For the SCR cases the NH3 slip is 22 tonnes/yr + NH3 safety concerns

(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btu's per year.

(h) DLN average cost based on 15 year life and long term bond rate

(i) The DLN NOx estimate NOx emissions of 20 ppmv are based on a GE 7EA gas turbine interpolted to 70 MW.
A Siemens SGT800 is guaranteed for 15 ppmv and the new GE DLN1+ is guaranteed for 9 ppmv below - 12C and 5 ppmv above -12C
At 15 ppm the SCR would still be incrementally cost effective versus DLN ($7,600/ton). An SCR would not be cost effective versus a DLN1+

(j) Assumed a Low NOx duct burner with a NOx emission factor of 38 g/GJ. The alternate is the new Dual Recirculaton duct burner with an emission factor of 22 g/GJ.
Adding an SCR would still be incrementally cost effective ($7200/ton) with a Dual Recirculation Duct Burner.

(k) The USEPA uses a rough guideline for cost effectiveness of $10,000/ton emissions reduction. This number is adjusted up or down depending on whether the incremental technology has positive or negative other environmental impacts and whether the incremental technology has positive or negative impacts on energy consumption

SUMMARY OF BATEA ECONOMIC ANALYSIS
70 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

70 MW	COMBINED CYCLE		SAGD - OTSG		STEAM RAISING (max)		STEAM RAISING (min)	
Commodity Factor	0.139	MWh / GJ	488	kg / GJ	440	kg / GJ	330	kg / GJ
FG Temp	100	°C	215	°C	115	°C	115	°C
GT Firing	770	GJ/h						
Duct Firing	668.5	GJ/h						
% Duct Firing	44%							
HRSG Output	1020	GJ/h	909	GJ/h	1005.5	GJ/h	1005.5	GJ/h
Commodity Output	141.7	MW	444	tonne/h	442	tonne/h	332	tonne/h
GT Output	70	MW						
Incremental Cost for Control	$/kWh		$/kWh	$/tonne steam	$/kWh	$/tonne steam	$/kWh	$/tonne steam
DLN Burners ($1.0 MM capital cost)(h)	0.00006		0.00011	0.013	0.00011	0.013	0.00011	0.018
Diffusion Burners + SCR	0.00115		0.00195	0.243	0.00195	0.243	0.00195	0.324
DLN Burners + SCR	0.00122		0.00205	0.256	0.00205	0.256	0.00205	0.342

Cases

Combined Cycle – The steam generated at the HRSG drives a steam turbine to generate additional electricity. The flue gas stack temperature is assumed to be 100℃ (see section D), and the efficiency of conver ting the heat recovered at the HRSG to the electricity generated at the steam turbine, is assumed to be 50%.

SAGD – Steam is generated in a once-through steam generator. The flue gas stack temperature is assumed to be 215℃ (see section D). The boiler feedwater temperature is assumed to be 200℃, and the steam r aising pressure 11200 KPag.

Steam Raising (max) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

Steam Raising (min) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

The **Commodity Output** is the amount of commodity generated (electricity or steam) for each case.
The **Incremental Cost of Control** is calculated on a per commodity basis, taking the incremental costs for each control case from the BAT Cost Tables.
Where steam is generated in the SAGD and Steam Raising situations the control cost is allocated in part to each commodity by the ratio of the fuels fired at the gas turbine and HRSG. For example, if 70% of the fuel is fired in the gas turbine, then 70% of the control cost is assigned to the electricity generated at the gas turbine. The remaining 30% of the control cost is assigned to the steam generated in the HRSG.

CAPITAL COST

SCR FOR 70MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

Cost Item	Factor
Direct Costs	
Purchased Equipment Costs	
SCR + auxiliary equipment + 300,000 NH3 Storage =A [b]	$ 2,950,000
Catalyst = $880,000 (30% of SCR System)	$ -
Instrumentation (10 % of A)	$ 295,000
Sales taxes (3 % of A)	$ 88,500
Freight (5 % of A)	$ 147,500
Purchased equipment cost, PEC (B=1.18A)	$ 3,481,000
Direct installation costs	
Foundations & supports (8 % of PEC)	$ 278,480
Handling & erection (14 % of PEC)	$ 487,340
Electrical (4 % of PEC)	$ 139,240
Piping (2 % of PEC)	$ 69,620
Insulation for ductwork (1 % of PEC)	$ 34,810
Painting (1 % of PEC)	$ 34,810
Direct installation cost (0.30 B)	$ 1,044,300
Site preparation, as required	$ -
Buildings, as required	$ -
Total Direct Cost, DC	$ 4,525,300
Indirect Costs (installation)	
Engineering (10 % of PEC)	$ 348,100
Construction and field expenses (5 % of PEC)	$ 174,050
Contractor fees (10 % of PEC)	$ 348,100
Start-up (2 % of PEC)	$ 69,620
Performance test (1 % of PEC)	$ 34,810
Contingencies (3 % of PEC)	$ 104,430
Total Indirect Cost, IC	$ 1,079,110
Total Capital Investment, TIC = DC + IC	$ 5,604,410
Cost Multiplier for Alberta (1.5)	1.5
Total Capital Investment Based on Alberta Costs	$ 8,406,615
Cost Multiplier for recent Jacobs Cost Est/EPA cost Est	$ 1.29
Total Capital Investment	$ 10,844,533

ANNUAL OPERATING COST
SCR SYSTEM FOR 70MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

Cost Item	Cost, $/Year
Total Capital Costs (TIC)	$ 10,844,533
Direct Annual Costs, DAC [c]	
Operating labor	
Operator (1/2 hour per shift, @$25/hr)	$ 13,688
Supervisor(15% of operator)	$ 2,053
Operating materials	
Fuel (Natural Gas) @ $6.9/MMBtu, 0.43 MMBtu/hr, & 8,760 hrs/yr	$ 25,991
Maintenance	
Labor (1/2 hour per shift)	$ 13,688
Material (100% of maintenance labor)	$ 13,688
Electricity	
(7.6 kW x 8760 hrs/yr x 0.0618/kW-hr)	$ 4,114
Catalyst Replacement Cost (30% of Equipment Cost/5 year life)	$ 176,000
NH3 Cost (46 # pure NH3/hr X $1000/ton X 8760 hours/year/2000 #/ton)	$ 201,480
Direct Annual Cost (DAC)	$ 450,701
Indirect Annual Costs, IAC	
Overhead (60 % of direct labor and maintenance)	$ 25,869
Administrative charges (2 % of TIC)	$ 216,891
Property tax (1 % of TIC)	$ 108,445
Insurance (1 % of TIC)	$ 108,445
Capital recovery [b]	$ 1,266,962
Interest or long term bond rate, i = 0.08	
Capital Recovery cost factr = 0.117	
Indirect Annual Cost (IAC)	$ 1,726,613
Total Annual Cost	$ 2,177,314

a. Chapter 3: OAQPS Control Cost Manual, Sixth Edition
b. The capital recovery cost factor is based on 15 year equipment life and a 7 Jan 2010 Bank of Canada Bond rate
USEPA BACT Manual Appendix B equation for capital recovery factor = i*(1+i)^n/[(1+i)^n -1]

SUMMARY OF BATEA ECONOMIC ANALYSIS
70 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

Pollutant/ Emissions Unit	Control Alternative	Emissions (a)		Emissions Reduction (a)	ECONOMIC IMPACT ANALYSIS			ENVIRONMENTAL IMPACTS		ENERGY IMPACTS
		(lb/hr)	(tpy)	(tpy)	Total Annualized Cost (b) ($/yr)	Average Cost Effectiveness (c) ($/tonne)	Incremental Incremental Cost Effectiveness (d) ($/tonne)	Toxic Impacts (e) (Yes/No)	Adverse Environmental Impacts (f) (Yes/No)	Incremental Increase Over Baseline (g) (MMBtu/Yr)
Cogen NOx Reduction	Baseline NOx Emissions - Diffusion Burners + duct burners	---	2143							
	DLN Burners ($1.0 MM capital cost)(h)		449	1694.0	$116,830	$69	$69	No	No	No
	Diffusion Burners + SCR		214	1929.0	$2,177,314	$1,129	$8,768	No	Yes	Yes (3800)
	DLN Burners + SCR		45	2098.0	$2,294,143	$1,093	$5,389	No	Yes	Yes (3800)
	Based on the above DLN burners have a cost effectiveness < $10,000/ton. Adding an SCR to a DLN burner has a cost effectiveness < $10,000/ton. Going to a diffusion burner + SCR verus a DLN burner has a cost effectiveness < $10,000/ton. Cost effectiveness is based on an assumed 20 ppmv NOx in the turbine exhaust. (k)									
	SCR cost/kWh = SCR annualized cost/8760 hours/yr/70,000 kW =				$0.00355					

(a) Emissions Reduction over baseline level. Emissions are shown in metric tonnes, not short tons. Emissions are based on 100% service factor

(b) Total Annualized Cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation)

(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.

(d) The Incremental Cost Effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives. In this case the SCR options are both compared with the DLN option.

(e) Toxics impact means there is a toxics impact consideration for the control alternative.

(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative. For the SCR cases the NH3 slip is 22 tonnes/yr + NH3 safety concerns

(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btu's per year.

(h) DLN average cost based on 15 year life and long term bond rate

(i) The DLN NOx estimate NOx emissions of 20 ppmv are based on a GE 7EA gas turbine interpolted to 70 MW.
A Siemens SGT800 is guaranteed for 15 ppmv and the new GE DLN1+ is guaranteed for 9 ppmv below - 12C and 5 ppmv above -12C
At 15 ppm the SCR would still be incrementally cost effective versus DLN ($7,600/ton). An SCR would not be cost effective versus a DLN1+

(j) Assumed a Low NOx duct burner with a NOx emission factor of 38 g/GJ. The alternate is the new Dual Recirculaton duct burner with an emission factor of 22 g/GJ.
Adding an SCR would still be incrementally cost effective ($7200/ton) with a Dual Recirculation Duct Burner.

(k) The USEPA uses a rough guideline for cost effectiveness of $10,000/ton emissions reduction. This number is adjusted up or down depending on whether the incremental technology has positive or negative other environmental impacts and whether the incremental technology has positive or negative impacts on energy consumption

SUMMARY OF BATEA ECONOMIC ANALYSIS
70 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

70 MW	COMBINED CYCLE		SAGD - OTSG		STEAM RAISING (max)		STEAM RAISING (min)	
Commodity Factor	0.139	MWh / GJ	488	kg / GJ	440	kg / GJ	330	kg / GJ
FG Temp	100	°C	215	°C	115	°C	115	°C
GT Firing	770	GJ/h						
Duct Firing	668.5	GJ/h						
% Duct Firing	44%							
HRSG Output	1020	GJ/h	909	GJ/h	1005.5	GJ/h	1005.5	GJ/h
Commodity Output	141.7	MW	444	tonne/h	442	tonne/h	332	tonne/h
GT Output	70	MW						
Incremental Cost for Control	$/kWh		$/kWh	$/tonne steam	$/kWh	$/tonne steam	$/kWh	$/tonne steam
DLN Burners ($1.0 MM capital cost)(h)	0.00006		0.00011	0.013	0.00011	0.013	0.00011	0.018
Diffusion Burners + SCR	0.00117		0.00198	0.247	0.00198	0.248	0.00198	0.330
DLN Burners + SCR	0.00124		0.00209	0.260	0.00209	0.261	0.00209	0.348

Cases

Combined Cycle – The steam generated at the HRSG drives a steam turbine to generate additional electricity. The flue gas stack temperature is assumed to be 100℃ (see section D), and the efficiency of converting the heat recovered at the HRSG to the electricity generated at the steam turbine, is assumed to be 50%.

SAGD – Steam is generated in a once-through steam generator. The flue gas stack temperature is assumed to be 215℃ (see section D). The boiler feedwater temperature is assumed to be 200℃, and the steam raising pressure 11200 KPag.

Steam Raising (max) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, for a boiler feedwater temperature of 100℃. This case represents the maximum steam raising capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

Steam Raising (min) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, for a boiler feedwater temperature of 100℃. This case represents the maximum steam raising capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

The **Commodity Output** is the amount of commodity generated (electricity or steam) for each case.
The **Incremental Cost of Control** is calculated on a per commodity basis, taking the incremental costs for each control case from the BAT Cost Tables.
Where steam is generated in the SAGD and Steam Raising situations the control cost is allocated in part to each commodity by the ratio of the fuels fired at the gas turbine and HRSG. For example, if 70% of the fuel is fired in the gas turbine, then 70% of the control cost is assigned to the electricity generated at the gas turbine. The remaining 30% of the control cost is assigned to the steam generated in the HRSG.

CAPITAL COST
SCR FOR 85MW COGEN SYSTEM WITHOUT DUCT BURNERS

Cost Item		Factor
Direct Costs		
Purchased Equipment Costs		
SCR + auxiliary equipment + 300,000 NH3 Storage =A [b]		$ 3,190,000
Catalyst = $950,000	(30% of SCR System)	$ -
Instrumentation (10 % of A)		$ 319,000
Sales taxes (3 % of A)		$ 95,700
Freight (5 % of A)		$ 159,500
Purchased equipment cost, PEC (B=1.18A)		$ 3,764,200
Direct installation costs		
Foundations & supports (8 % of PEC)		$ 301,136
Handling & erection (14 % of PEC)		$ 526,988
Electrical (4 % of PEC)		$ 150,568
Piping (2 % of PEC)		$ 75,284
Insulation for ductwork (1 % of PEC)		$ 37,642
Painting (1 % of PEC)		$ 37,642
Direct installation cost (0.30 B)		$ 1,129,260
Site preparation, as required		$ -
Buildings, as required		$ -
	Total Direct Cost, DC	$ 4,893,460
Indirect Costs (installation)		
Engineering (10 % of PEC)		$ 376,420
Construction and field expenses (5 % of PEC)		$ 188,210
Contractor fees (10 % of PEC)		$ 376,420
Start-up (2 % of PEC)		$ 75,284
Performance test (1 % of PEC)		$ 37,642
Contingencies (3 % of PEC)		$ 112,926
	Total Indirect Cost, IC	$ 1,166,902
Total Capital Investment, TIC = DC + IC		$ 6,060,362
Cost Multiplier for Alberta (1.5)		1.5
Total Capital Investment Based on Alberta Costs		$ 9,090,543
Cost Multiplier for recent Jacobs Cost Est/EPA cost Est		$ 1.29
Total Capital Investment		$ 11,726,800

ANNUAL OPERATING COST
SCR SYSTEM FOR 85MW COGEN SYSTEM WITHOUT DUCT BURNERS

Cost Item	Cost, $/Year
Total Capital Costs (TIC)	$ 11,726,800
Direct Annual Costs, DAC [c]	
Operating labor	
Operator (1/2 hour per shift, @$25/hr)	$ 13,688
Supervisor(15% of operator)	$ 2,053
Operating materials	
Fuel (Natural Gas) @ $6.9/MMBtu, 0.30 MMBtu/hr, & 8,760 hrs/yr	$ 18,133
Maintenance	
Labor (1/2 hour per shift)	$ 13,688
Material (100% of maintenance labor)	$ 13,688
Electricity	
(5.2 kW x 8760 hrs/yr x 0.0618/kW-hr)	$ 2,815
Catalyst Replacement Cost (30% of Equipment Cost/5 year life)	$ 190,000
NH3 Cost (32 # pure NH3/hr X $1000/ton X 8760 hours/year/2000 #/ton)	$ 140,160
Direct Annual Cost (DAC)	$ 394,224
Indirect Annual Costs, IAC	
Overhead (60 % of direct labor and maintenance)	$ 25,869
Administrative charges (2 % of TIC)	$ 234,536
Property tax (1 % of TIC)	$ 117,268
Insurance (1 % of TIC)	$ 117,268
Capital recovery [b]	$ 1,370,037
Interest or long term bond rate, i = 0.08	
Capital Recovery cost factr = 0.117	
Indirect Annual Cost (IAC)	$ 1,864,978
Total Annual Cost	$ 2,259,202

a. Chapter 3: OAQPS Control Cost Manual, Sixth Edition

b. The capital recovery cost factor is based on 15 year equipment life and a 7 Jan 2010 Bank of Canada Bond rate
USEPA BACT Manual Appendix B equation for capital recovery factor = i*(1+i)^n/[(1+i)^n -1]

SUMMARY OF BATEA ECONOMIC ANALYSIS
85 MW GAS TURBINE COGEN SYSTEM WITHOUT DUCT BURNERS

Pollutant/ Emissions Unit	Control Alternative	Emissions (a) (lb/hr)	Emissions (a) (tpy)	Emissions Reduction (a) (tpy)	ECONOMIC IMPACT ANALYSIS: Total Annualized Cost (b) ($/yr)	ECONOMIC IMPACT ANALYSIS: Average Cost Effectiveness (c) ($/tonne)	ECONOMIC IMPACT ANALYSIS: Incremental Incremental Cost Effectiveness (d) ($/tonne)	ENVIRONMENTAL IMPACTS: Toxic Impacts (e) (Yes/No)	ENVIRONMENTAL IMPACTS: Adverse Environmental Impacts (f) (Yes/No)	ENERGY IMPACTS: Incremental Increase Over Baseline (g) (MMBtu/Yr)
Cogen NOx Reduction	Baseline NOx Emissions - Diffusion Burners + duct burners	---	2340							
	DLN Burners ($1.0 MM capital cost)		276	2064.0	$116,830	$57	$57	No	No	No
	Diffusion Burners + SCR		234	2106.0	$2,259,202	$1,073	$51,009	No	Yes	Yes (2600)
	DLN Burners + SCR		23	2317.0	$2,376,032	$1,025	$8,930	No	Yes	Yes (2600)
	Based on the above DLN burners have a cost effectiveness of < $10,000/ton. Adding an SCR to a DLN burner has a cost effectiveness < $10,000/ton. Going to a diffusion burner + SCR verus a DLN burner has a cost effectiveness > $10,000/ton. Cost effectiveness is based on an assumed 20 ppm NOx in the turbine exhaust (j)									
	SCR cost/kWh = SCR annualized cost/8760 hours/yr/70,000 kW =				$0.00368					

(a) Emissions Reduction over baseline level. Emissions are shown in metric tonnes, not short tons. Emissions are based on 100% service factor

(b) Total Annualized Cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation)

(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.

(d) The Incremental Cost Effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives. In this case both

(e) Toxics impact means there is a toxics impact consideration for the control alternative.

(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative. For the SCR cases the NH3 slip is 25 tonnes/yr + NH3 safety concerns

(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btu's per year.

(h) DLN average cost based on 15 year life and long term bond rate

(i) The DLN NOx estimate NOx emissions of 20 ppmv are based on a GE 7EA gas turbine interpolted to 70 MW.
A Siemens SGT800 is guaranteed for 15 ppmv and the new GE DLN1+ is guaranteed for 9 ppmv below - 12C and 5 ppmv above -12C
At 15 ppm the SCR would be marginally not cost effective versus DLN ($10,800/ton). An SCR would not be cost effective versus a DLN1+

(j) The USEPA uses a rough guideline for cost effectiveness of $10,000/ton emissions reduction. This number is adjusted up or down depending on whether the incremental technology has positive or negative other environmental impacts and whether the incremental technology has positive or negative impacts on energy consumption

SUMMARY OF BATEA ECONOMIC ANALYSIS
85 MW GAS TURBINE COGEN SYSTEM WITHOUT DUCT BURNERS

85.4 MW	COMBINED CYCLE		SAGD - OTSG		STEAM RAISING (max)		STEAM RAISING (min)	
Commodity Factor	0.139	MWh / GJ	488	kg / GJ	440	kg / GJ	330	kg / GJ
FG Temp	100	°C	215	°C	115	°C	115	°C
GT Firing	939.4	GJ/h						
Duct Firing	0	GJ/h						
% Duct Firing	0%							
HRSG Output	509.4	GJ/h	379.8	GJ/h	492.5	GJ/h	492.5	GJ/h
Commodity Output	70.8	MW	185	tonne/h	217	tonne/h	163	tonne/h
GT Output	85.4	MW						
Incremental Cost for Control	$/kWh		$/kWh	$/tonne steam	$/kWh	$/tonne steam	$/kWh	$/tonne steam
DLN Burners ($1.0 MM capital cost)	0.00009		0.00016	0.000	0.00016	0.000	0.00016	0.000
Diffusion Burners + SCR	0.00165		0.00302	0.000	0.00302	0.000	0.00302	0.000
DLN Burners + SCR	0.00174		0.00318	0.000	0.00318	0.000	0.00318	0.000

Cases

Combined Cycle – The steam generated at the HRSG drives a steam turbine to generate additional electricity. The flue gas stack temperature is assumed to be 100℃ (see section D), and the efficiency of convertin g the heat recovered at the HRSG to the electricity generated at the steam turbine, is assumed to be 50%.

SAGD – Steam is generated in a once-through steam generator. The flue gas stack temperature is assumed to be 215°C (see section D). The boiler feedwater temperature is assumed to be 200℃, and the steam rais ing pressure 11200 KPag.

Steam Raising (max) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, for a bo iler feedwater temperature of 100℃. This case represents the maximum steam raising capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500℃)

Steam Raising (min) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, for a bo iler feedwater temperature of 100℃. This case represents the maximum steam raising capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500℃)

The **Commodity Output** is the amount of commodity generated (electricity or steam) for each case.
The **Incremental Cost of Control** is calculated on a per commodity basis, taking the incremental costs for each control case from the BAT Cost Tables.
Where steam is generated in the SAGD and Steam Raising situations the control cost is allocated in part to each commodity by the ratio of the fuels fired at the gas turbine and HRSG. For example, if 70% of the fuel is fired in the gas turbine, then 70% of the control cost is assigned to the electricity generated at the gas turbine. The remaining 30% of the control cost is assigned to the steam generated in the HRSG.

CAPITAL COST
SCR FOR 85MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

Cost Item		Factor
Direct Costs		
Purchased Equipment Costs		
SCR + auxiliary equipment + 300,000 NH3 Storage =A [b]		$ 3,300,000
Catalyst = $1,000,000	(30% of SCR System)	$ -
Instrumentation (10 % of A)		$ 330,000
Sales taxes (3 % of A)		$ 99,000
Freight (5 % of A)		$ 165,000
Purchased equipment cost, PEC (B=1.18A)		$ 3,894,000
Direct installation costs		
Foundations & supports (8 % of PEC)		$ 311,520
Handling & erection (14 % of PEC)		$ 545,160
Electrical (4 % of PEC)		$ 155,760
Piping (2 % of PEC)		$ 77,880
Insulation for ductwork (1 % of PEC)		$ 38,940
Painting (1 % of PEC)		$ 38,940
Direct installation cost (0.30 B)		$ 1,168,200
Site preparation, as required		$ -
Buildings, as required		$ -
Total Direct Cost, DC		$ 5,062,200
Indirect Costs (installation)		
Engineering (10 % of PEC)		$ 389,400
Construction and field expenses (5 % of PEC)		$ 194,700
Contractor fees (10 % of PEC)		$ 389,400
Start-up (2 % of PEC)		$ 77,880
Performance test (1 % of PEC)		$ 38,940
Contingencies (3 % of PEC)		$ 116,820
Total Indirect Cost, IC		$ 1,207,140
Total Capital Investment, TIC = DC + IC		$ 6,269,340
Cost Multiplier for Alberta (1.5)		1.5
Total Capital Investment Based on Alberta Costs		$ 9,404,010
Cost Multiplier for recent Jacobs Cost Est/EPA cost Est		$ 1.29
Total Capital Investment		$ 12,131,173

ANNUAL OPERATING COST
SCR SYSTEM FOR 85MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

Cost Item	Cost, $/Year
Total Capital Costs (TIC)	$12,131,173
Direct Annual Costs, DAC [c]	
Operating labor	
Operator (1/2 hour per shift, @$25/hr)	$ 13,688
Supervisor(15% of operator)	$ 2,053
Operating materials	
Fuel (Natural Gas) @ $6.9/MMBtu, 0.43 MMBtu/hr, & 8,760 hrs/yr	$ 25,991
Maintenance	
Labor (1/2 hour per shift)	$ 13,688
Material (100% of maintenance labor)	$ 13,688
Electricity	
(7.6 kW x 8760 hrs/yr x 0.0618/kW-hr)	$ 4,114
Catalyst Replacement Cost (30% of Equipment Cost/5 year life)	$ 200,000
NH3 Cost (46 # pure NH3/hr X $1000/ton X 8760 hours/year/2000 #/ton)	$ 201,480
Direct Annual Cost (DAC)	$ 474,701
Indirect Annual Costs, IAC	
Overhead (60 % of direct labor and maintenance)	$ 25,869
Administrative charges (2 % of TIC)	$ 242,623
Property tax (1 % of TIC)	$ 121,312
Insurance (1 % of TIC)	$ 121,312
Capital recovery [b]	$ 1,417,279
Interest or long term bond rate, i = 0.08	
Capital Recovery cost factr = 0.117	
Indirect Annual Cost (IAC)	$ 1,928,396
Total Annual Cost	$ 2,403,097

a. Chapter 3: OAQPS Control Cost Manual, Sixth Edition
b. The capital recovery cost factor is based on 15 year equipment life and a 7 Jan 2010 Bank of Canada Bond rate
USEPA BACT Manual Appendix B equation for capital recovery factor = i*(1+i)^n/[(1+i)^n -1]

SUMMARY OF BATEA ECONOMIC ANALYSIS
85 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

Pollutant/ Emissions Unit	Control Alternative	Emissions (a) (lb/hr)	Emissions (a) (tpy)	Emissions Reduction (a) (tpy)	ECONOMIC IMPACT ANALYSIS: Total Annualized Cost (b) ($/yr)	ECONOMIC IMPACT ANALYSIS: Average Cost Effectiveness (c) ($/tonne)	ECONOMIC IMPACT ANALYSIS: Incremental Incremental Cost Effectiveness (d) ($/tonne)	ENVIRONMENTAL IMPACTS: Toxic Impacts (e) (Yes/No)	ENVIRONMENTAL IMPACTS: Adverse Environmental Impacts (f) (Yes/No)	ENERGY IMPACTS: Incremental Increase Over Baseline (g) (MMBtu/Yr)
Cogen NOx Reduction	Baseline NOx Emissions - Diffusion Burners + duct burners	---	2488							
	DLN Burners ($1.0 MM capital cost)(h)		424	2064.0	$116,830	$57	$57	No	No	No
	Diffusion Burners + SCR		249	2239.0	$2,403,097	$1,073	$13,064	No	Yes	Yes (3800)
	DLN Burners + SCR		42	2446.0	$2,519,926	$1,030	$6,291	No	Yes	Yes (3800)
	Based on the above DLN burners have a cost effectiveness < $10,000/ton. Adding an SCR to a DLN burner has a cost effectiveness < $10,000/ton. Going to a diffusion burner + SCR verus a DLN burner has a cost effectiveness < $10,000/ton. Cost effectiveness									
	SCR cost/kWh = SCR annualized cost/8760 hours/yr/70,000 kW =				$0.00392					

(a) Emissions Reduction over baseline level. Emissions are shown in metric tonnes, not short tons. Emissions are based on 100% service factor

(b) Total Annualized Cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation)

(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.

(d) The Incremental Cost Effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives. In this case the

(e) Toxics impact means there is a toxics impact consideration for the control alternative.

(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative. For the SCR cases the NH_3 slip is 25 tonnes/yr + NH_3 safety concerns

(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btu's per year.

(h) DLN average cost based on 15 year life and long term bond rate

(i) The DLN NOx estimate NOx emissions of 20 ppmv are based on a GE 7EA gas turbine interpolted to 70 MW.
A Siemens SGT800 is guaranteed for 15 ppmv and the new GE DLN1+ is guaranteed for 9 ppmv below - 12C and 5 ppmv above -12C
At 15 ppm the SCR would still be incrementally cost effective versus DLN ($7,600/ton). An SCR would not be cost effective versus a DLN1+

(j) Assumed a Low NOx duct burner with a NOx emission factor of 38 g/GJ. The alternate is the new Dual Recirculaton duct burner with an emission factor of 22 g/GJ.
Adding an SCR would still be incrementally cost effective ($7200/ton) with a Dual Recirculation Duct Burner.

(k) The USEPA uses a rough guideline for cost effectiveness of $10,000/ton emissions reduction. This number is adjusted up or down depending on whether the incremental technology has positive or negative other environmental impacts and whether the incremental technology has positive or negative impacts on energy consumption

SUMMARY OF BATEA ECONOMIC ANALYSIS
85 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 840C

85.4 MW	COMBINED CYCLE		SAGD - OTSG		STEAM RAISING (max)		STEAM RAISING (min)	
Commodity Factor	0.139	MWh / GJ	488	kg / GJ	440	kg / GJ	330	kg / GJ
FG Temp	100	°C	215	°C	115	°C	115	°C
GT Firing	939.4	GJ/h						
Duct Firing	815.6	GJ/h						
% Duct Firing	44%							
HRSG Output	1244	GJ/h	1109	GJ/h	1226.4	GJ/h	1226.4	GJ/h
Commodity Output	172.8	MW	541	tonne/h	540	tonne/h	405	tonne/h
GT Output	85.4	MW						
Incremental Cost for Control	$/kWh		$/kWh	$/tonne steam	$/kWh	$/tonne steam	$/kWh	$/tonne steam
DLN Burners ($1.0 MM capital cost)(h)	0.00005		0.00009	0.011	0.00009	0.011	0.00009	0.015
Diffusion Burners + SCR	0.00106		0.00180	0.224	0.00180	0.224	0.00180	0.299
DLN Burners + SCR	0.00111		0.00188	0.234	0.00188	0.235	0.00188	0.313

Cases

Combined Cycle – The steam generated at the HRSG drives a steam turbine to generate additional electricity. The flue gas stack temperature is assumed to be 100℃ (see section D), and the efficiency of conver ting the heat recovered at the HRSG to the electricity generated at the steam turbine, is assumed to be 50%.

SAGD – Steam is generated in a once-through steam generator. The flue gas stack temperature is assumed to be 215℃ (see section D). The boiler feedwater temperature is assumed to be 200℃, and the steam r aising pressure 11200 KPag.

Steam Raising (max) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

Steam Raising (min) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, fo r a boiler feedwater temperature of 100℃. This case represents the maximum steam raisi ng capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

The **Commodity Output** is the amount of commodity generated (electricity or steam) for each case.
The **Incremental Cost of Control** is calculated on a per commodity basis, taking the incremental costs for each control case from the BAT Cost Tables.
Where steam is generated in the SAGD and Steam Raising situations the control cost is allocated in part to each commodity by the ratio of the fuels fired at the gas turbine and HRSG. For example, if 70% of the fuel is fired in the gas turbine, then 70% of the control cost is assigned to the electricity generated at the gas turbine. The remaining 30% of the control cost is assigned to the steam generated in the HRSG.

CAPITAL COST
SCR FOR 85MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

Cost Item		Factor
Direct Costs		
Purchased Equipment Costs		
SCR + auxiliary equipment + 300,000 NH3 Storage =A [b]		$ 3,300,000
Catalyst = $1,000,000	(30% of SCR System)	$ -
Instrumentation (10 % of A)		$ 330,000
Sales taxes (3 % of A)		$ 99,000
Freight (5 % of A)		$ 165,000
Purchased equipment cost, PEC (B=1.18A)		$ 3,894,000
Direct installation costs		
Foundations & supports (8 % of PEC)		$ 311,520
Handling & erection (14 % of PEC)		$ 545,160
Electrical (4 % of PEC)		$ 155,760
Piping (2 % of PEC)		$ 77,880
Insulation for ductwork (1 % of PEC)		$ 38,940
Painting (1 % of PEC)		$ 38,940
Direct installation cost (0.30 B)		$ 1,168,200
Site preparation, as required		$ -
Buildings, as required		$ -
Total Direct Cost, DC		$ 5,062,200
Indirect Costs (installation)		
Engineering (10 % of PEC)		$ 389,400
Construction and field expenses (5 % of PEC)		$ 194,700
Contractor fees (10 % of PEC)		$ 389,400
Start-up (2 % of PEC)		$ 77,880
Performance test (1 % of PEC)		$ 38,940
Contingencies (3 % of PEC)		$ 116,820
Total Indirect Cost, IC		$ 1,207,140
Total Capital Investment, TIC = DC + IC		$ 6,269,340
Cost Multiplier for Alberta (1.5)		1.5
Total Capital Investment Based on Alberta Costs		$ 9,404,010
Cost Multiplier for recent Jacobs Cost Est/EPA cost Est		$ 1.29
Total Capital Investment		$ 12,131,173

ANNUAL OPERATING COST
SCR SYSTEM FOR 85MW COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

Cost Item		Cost, $/Year
Total Capital Costs (TIC)		$12,131,173
Direct Annual Costs, DAC [c]		
Operating labor		
Operator (1/2 hour per shift, @$25/hr)		$ 13,688
Supervisor(15% of operator)		$ 2,053
Operating materials		
Fuel (Natural Gas) @ $6.9/MMBtu, 0.55 MMBtu/hr, & 8,760 hrs/yr		$ 33,244
Maintenance		
Labor (1/2 hour per shift)		$ 13,688
Material (100% of maintenance labor)		$ 13,688
Electricity		
(9.6 kW x 8760 hrs/yr x 0.0618/kW-hr)		$ 5,197
Catalyst Replacement Cost (30% of Equipment Cost/5 year life)		$ 200,000
NH3 Cost (58 # pure NH3/hr X $1000/ton X 8760 hours/year/2000 #/ton)		$ 254,040
Direct Annual Cost (DAC)		$ 535,597
Indirect Annual Costs, IAC		
Overhead (60 % of direct labor and maintenance)		$ 25,869
Administrative charges (2 % of TIC)		$ 242,623
Property tax (1 % of TIC)		$ 121,312
Insurance (1 % of TIC)		$ 121,312
Capital recovery [b]		$ 1,417,279
Interest or long term bond rate, i =	0.08	
Capital Recovery cost factr =	0.117	
Indirect Annual Cost (IAC)		$ 1,928,396
Total Annual Cost		$ 2,463,993

a. Chapter 3: OAQPS Control Cost Manual, Sixth Edition
b. The capital recovery cost factor is based on 15 year equipment life and a 7 Jan 2010 Bank of Canada Bond rate
USEPA BACT Manual Appendix B equation for capital recovery factor = i*(1+i)^n/[(1+i)^n -1]

SUMMARY OF BATEA ECONOMIC ANALYSIS
85 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

Pollutant/ Emissions Unit	Control Alternative	Emissions (a) (lb/hr)	Emissions (a) (tpy)	Emissions Reduction (a) (tpy)	ECONOMIC IMPACT ANALYSIS: Total Annualized Cost (b) ($/yr)	ECONOMIC IMPACT ANALYSIS: Average Cost Effectiveness (c) ($/tonne)	ECONOMIC IMPACT ANALYSIS: Incremental Incremental Cost Effectiveness (d) ($/tonne)	ENVIRONMENTAL IMPACTS: Toxic Impacts (e) (Yes/No)	ENVIRONMENTAL IMPACTS: Adverse Environmental Impacts (f) (Yes/No)	ENERGY IMPACTS: Incremental Increase Over Baseline (g) (MMBtu/Yr)
Cogen NOx Reduction	Baseline NOx Emissions - Diffusion Burners + duct burners	---	2610							
	DLN Burners ($1.0 MM capital cost)(h)		546	2064.0	$116,830	$57	$57	No	No	No
	Diffusion Burners + SCR		261	2349.0	$2,463,993	$1,049	$8,236	No	Yes	Yes (4800)
	DLN Burners + SCR		55	2555.0	$2,580,822	$1,010	$5,018	No	Yes	Yes (4800)
	Based on the above DLN burners have a cost effectiveness < $10,000/ton. Adding an SCR to a DLN burner has a cost effectiveness < $10,000/ton. Going to a diffusion burner + SCR verus a DLN burner has a cost effectiveness < $10,000/ton. Cost effectiveness is based on an assumed 20 ppmv NOx in the turbine exhaust (k)									
	SCR cost/kWh = SCR annualized cost/8760 hours/yr/70,000 kW =				$0.00402					

(a) Emissions Reduction over baseline level. Emissions are shown in metric tonnes, not short tons. Emissions are based on 100% service factor

(b) Total Annualized Cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation)

(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.

(d) The Incremental Cost Effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives. In this case the

(e) Toxics impact means there is a toxics impact consideration for the control alternative.

(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative. For the SCR cases the NH3 slip is 25 tonnes/yr + NH3 safety concerns

(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btu's per year.

(h) DLN average cost based on 15 year life and long term bond rate

(i) The DLN NOx estimate NOx emissions of 20 ppmv are based on a GE 7EA gas turbine interpolted to 70 MW.
A Siemens SGT800 is guaranteed for 15 ppmv and the new GE DLN1+ is guaranteed for 9 ppmv below - 12C and 5 ppmv above -12C
At 15 ppm the SCR would still be incrementally cost effective versus DLN ($7,600/ton). An SCR would not be cost effective versus a DLN1+

(j) Assumed a Low NOx duct burner with a NOx emission factor of 38 g/GJ. The alternate is the new Dual Recirculaton duct burner with an emission factor of 22 g/GJ.
Adding an SCR would still be incrementally cost effective ($7200/ton) with a Dual Recirculation Duct Burner.

(k) The USEPA uses a rough guideline for cost effectiveness of $10,000/ton emissions reduction. This number is adjusted up or down depending on whether the incremental technology has positive or negative other environmental impacts and whether the incremental technology has positive or negative impacts on energy consumption

SUMMARY OF BATEA ECONOMIC ANALYSIS
85 MW GAS TURBINE COGEN SYSTEM WITH DUCT BURNERS FIRED TO 1070C

85.4 MW	COMBINED CYCLE		SAGD - OTSG		STEAM RAISING (max)		STEAM RAISING (min)	
Commodity Factor	0.139	MWh / GJ	488	kg / GJ	440	kg / GJ	330	kg / GJ
FG Temp	100	°C	215	°C	115	°C	115	°C
GT Firing	939.4	GJ/h						
Duct Firing	815.6	GJ/h						
% Duct Firing	44%							
HRSG Output	1244	GJ/h	1109	GJ/h	1226.4	GJ/h	1226.4	GJ/h
Commodity Output	172.8	MW	541	tonne/h	540	tonne/h	405	tonne/h
GT Output	85.4	MW						
Incremental Cost for Control	$/kWh		$/kWh	$/tonne steam	$/kWh	$/tonne steam	$/kWh	$/tonne steam
DLN Burners ($1.0 MM capital cost)(h)	0.00005		0.00009	0.011	0.00009	0.011	0.00009	0.015
Diffusion Burners + SCR	0.00109		0.00184	0.229	0.00184	0.230	0.00184	0.307
DLN Burners + SCR	0.00114		0.00193	0.240	0.00193	0.241	0.00193	0.321

Cases

Combined Cycle – The steam generated at the HRSG drives a steam turbine to generate additional electricity. The flue gas stack temperature is assumed to be 100℃ (see section D), and the efficiency of converting the heat recovered at the HRSG to the electricity generated at the steam turbine, is assumed to be 50%.

SAGD – Steam is generated in a once-through steam generator. The flue gas stack temperature is assumed to be 215℃ (see section D). The boiler feedwater temperature is assumed to be 200℃, and the steam raising pressure 11200 KPag.

Steam Raising (max) – Steam is generated in a drum type boiler. The flue gas stack temperature is assumed to be 115℃, for a boiler feedwater temperature of 100℃. This case represents the maximum steam raising capability over the range of steam pressures (350 to 11200 KPa) and temperatures (saturated to 500°C)

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