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GREENHOUSE GAS AND ECONOMIC IMPLICATIONS

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UNIVERSITY OF CALGARY

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Front page photography: Cover page photo of SAGD cogeneration unit by Joey Podlubny

Background and acknowledgements

CESAR's work on this report began in the spring of 2015 with a donation to the University of Calgary through the Edmonton Community Foundation that provided 60% of the project budget. In early 2016, Candor Engineering Inc. provided valuable technical and engineering insights regarding cogeneration that were incorporated into our models. They also made it possible for CESAR to second Eric Shewchuk, a talented electrical engineer to assist with the modeling work.

In late May 2016, preliminary results were shared with Alberta Innovates – Energy and Environmental Solutions and a number of oil sands companies, five of which expressed an interest in providing financial support for the work. Together with Alberta Innovates – Energy and Environmental Solutions*, MEG Energy, Suncor Energy, Cenovus Energy, Nexen Energy ULC, and one anonymous corporation, provided the remaining 40% of the project budget. CESAR thanks them for their support of this work.

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About CESAR

CESAR (Canadian Energy Systems Analysis Research) is an initiative that was started at the University of Calgary in 2013 to understand and inform energy systems change in Canada. By building data resources and visualization tools, analyzing past and present energy systems, and modeling energy futures, CESAR researchers work to inform policy and investment decisions regarding the transformation of Canada's energy systems towards sustainability. To carry out its work, CESAR brings researchers, disciplines and sectors together from across Canada.

Through its website (www.cesarnet.ca), CESAR provides visualizations that communicate a wealth of information on the energy systems of Canada, and its provinces. The data behind many of these visualizations have been made available through a cooperative agreement between CESAR and whatIf? Technologies Inc, an Ottawa, Ontario systems modeling company, and the owner and developer of the Canadian Energy Systems Simulator (CanESS) model.

In addition to generating publications in the traditional academic literature, CESAR produces detailed, timely reports / discussion papers under the 'CESAR Scenarios' publication series. These reports are made available for free download on the cesarnet.ca website.

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David Layzell is a Professor at the University of Calgary and Director of the Canadian Energy Systems Analysis Research (CESAR) Initiative. In CESAR, he studies the energy systems of Canada and models the costs, benefits and tradeoffs of technologies and policies driving energy systems transformation. Between 2008 and 2012, he was Executive Director of the Institute for Sustainable Energy, Environment and Economy (ISEEE), a cross-faculty, graduate research and training institute at the University of Calgary.

Before going to Calgary, Dr. Layzell was a professor at Queen's University (Kingston) and the Executive Director of BIOCAP Canada, a research foundation focused on biological solutions to climate change. While at Queen's, he founded an scientific instrumentation company called Qubit Systems Inc. and was elected 'Fellow of the Royal Society of Canada' (FRSC) for his research contributions.

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Eric Shewchuk is an electrical engineer at Candor Engineering in Calgary, where he has worked for 10 years. His main responsibilities include signing and stamping drawings, creating standards and technical lead on projects. With the cooperation and support of Candor Engineering, CESAR seconded him to work on its SAGD Cogeneration project.

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Eric has a BSc in Electrical Engineering from the University of Alberta, where he graduated with distinction. He is a member of the Association of Professional Engineers and Geoscientists of Alberta, the Association of Professional Engineers & Geoscientists of Saskatchewan, and the Association of Professional Engineers and Geoscientists of British Columbia.

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Dr Sit has worked with CESAR since January 2016, bringing valuable insights and expertise from his years of work in the oil industry.

Manfred Klein, BEng

CESAR Associate

Principal, MA Klein & Associates

Manfred Klein recently retired after 33 years in the Canadian federal government, most recently as Coordinator, Energy and Environment at the Gas Turbine Laboratory of the *National Research Council* in Ottawa.

He spent 16 years with *Environment Canada*, involved with CCME industrial air emissions guidelines for Gas Turbines and for Cement Kilns, using output-based environmental standards. He also helped to develop new taxation incentives to encourage cogeneration and district energy, provided inputs to environmental assessments, and organized various industrial training functions on gas turbine CHP systems. Prior to that, Mr. Klein was with the *National Energy Board* for 11 years, dealing with natural gas pipeline and compressor station construction inspection and certification.

Mr. Klein works now as an independent consultant on a wide range of environment and energy issues. He specializes in technical training for gas turbine applications, cogeneration, natural gas pipelines, and balanced analysis of integrated system solutions to GHGs, air pollution and system reliability. He has a Bachelor of Mechanical Engineering from Carleton University. Memberships have included:

- Former Chair of IAGT *Industrial Gas Turbine Applications* Committee
- Former Chair of *ASME / IGTI Environment & Regulatory Affairs Committee*
- Environmental R&D group of *Canadian Gas Association (CEPEI)*

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Abbreviations used

BFW	Boiler Feed Water
BPD	Barrels Per Day
BTF	Behind The Fence
CAC	Criteria Air Contaminants
CAPEX	Capital Expenditure
CHP	Combined Heat and Power
Cogen	Cogeneration
COSIA	Canada's Oil Sands Innovation Alliance
CPF	Central Processing Facility
CWE	Cold Water Equivalent
DB	Duct Burning
DLN	Dry Low NOx
ECM	Electrochemical Membrane
EGT	Exhaust Gas Temperature
FA-DB	Forced Air-Duct Burning
GHG	Greenhouse Gas
GT	Gas Turbine
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
LF	Load Factor
LHV	Lower Heating Value
LPG	Liquefied Petroleum Gas
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NGSC	Natural Gas Single Cycle
NPV	Net Present Value
OTSG	Once Through Steam Generator
PCC	Post Combustion Carbon Capture
PG	Produced Gas
PM	Particulate Matter
ROI	Return on Investment
SAGD	Steam Assisted Gravity Drainage
SAP	Solvent Aided Process
SGER	Specified Gas Emitters Regulation
SOFC	Solid Oxide Fuel Cell
SOR	Steam to Oil Ratio
TRL	Technology Readiness Level
VIGV	Variable Inlet Guide Vanes
VOC	Volatile Organic Compound
WHR	Waste Heat Recovery

Executive Summary

To address concerns about climate change, and regain public support for Alberta's oil production to access markets, the Alberta government has been developing policies and regulations aimed at reducing greenhouse gas (GHG) emissions. In addition to carbon taxes, energy efficiency programs and a 100-million-tonnes (Mt) cap on oil sands emissions, the government has committed to eliminate coal power emissions from the Alberta electrical grid by 2030 and replace two-thirds of coal's present day capacity with renewables.

To achieve climate change goals, the envisaged changes in technologies and practices have tended to be focused on individual industrial sectors. Cogeneration – or the simultaneous generation of electricity and industrial heat, is an example of a technology that can transcend sectorial boundaries, increase system level efficiency and reduce overall GHG emissions. At oil sands SAGD facilities, cogeneration can produce the required steam and power for oil sands production, and provide additional power to the public grid of Alberta.

This report is the first of two studies that explore the technical, environmental and economic implications of integrating large-scale changes in the electricity sector with changes in the heat and power generation technologies used by Steam Assisted Gravity Drainage (SAGD) to produce oil sands crude. Technical data from diverse sources were collected and compiled to create a detailed computer model of a 33,000 barrel per day (BPD) SAGD facility having steam to oil ratios (SOR) that varied from 2 to 4 barrels of water needed per barrel of crude recovered. Using the model, four different Case studies were built and compared, each differing in the technologies used to provide heat and power to the SAGD process and power to the public grid. The Cases were:

1. **Base Case** of SAGD with no cogeneration, but using a natural gas-fired, once through steam generator (OTSG) for SAGD steam and importing power from Alberta's public grid;
2. **One 85 MWe gas turbine at 100% load factor** plus heat recovery steam generator (HRSG) equipped for duct burning (at <40% of fuel rate supplied to gas turbine) to provide a portion of the

SAGD heat requirement and all of SAGD power needs, with the balance of electricity exported to the public grid. OTSGs provide the rest of the SAGD steam requirements.

3. **Two 85 MWe gas turbines at 100% load factor** plus heat recovery steam generator (HRSG) equipped for duct burning (at up to 40% of the fuel rate supplied to the gas turbines) to provide all of SAGD heat and power requirements with the balance of electricity exported to public grid.
4. **Two 85 MWe gas turbines at 60% load factor** plus heat recovery steam generator (HRSG) equipped for duct burning (at up to 40% of the fuel rate supplied to the gas turbines) to provide all of SAGD heat and power requirements and the balance of the electricity generated was exported to grid. The spare generation capacity for the gas turbines made it possible for them to provide backup for renewables power generation when required.

In the Base Case, electricity demand by the 33,000 BPD SAGD facility at a SOR of 2 was only 55% of that for a facility with a SOR of 4 due to lower electricity demand to move boiler feed water and combustion air. At any given SOR, SAGD facilities with Cogen (Cases 2, 3, 4) had a 10-15% lower demand for electricity than Base Case facilities that relied on the public grid. Most of this lower demand can be attributed to the fact that gas turbines in Cogen systems produce a large flow of hot air that can be delivered to a HRSG for additional natural gas combustion (duct burning) and steam generation. This reduces or eliminates the need for a blower to deliver combustion air as is required in the Base Case that uses OTSGs for steam generation.

At an SOR of 3, the Base Case drew grid power at a rate of 1.5 TJ/d (= 17 MW). However, the SAGD Cogen Cases not only met all their power needs, but put an additional 6 TJ/d (= 69 MW), 13.5 TJ/d (= 156 MW), or 7.6 TJ/d (= 88 MW) of electricity on the grid for Cases 2, 3 and 4, respectively.

When the Base Case was adjusted to match both the oil production and the public grid contribution that were observed in the three Cogen Cases, it was possible to compare the total energy input, conversion losses and GHG emissions associated with each Cogen Case. At a SOR of 3, Cogen was found to reduce fuel use by 11 to 16.5%, conversion losses by 31 to 40% and GHG emissions by 26 to 37%. The GHG emission reductions were equivalent to 1-2 kt CO_2/day, or 365-730 kt CO_2/ yr for each SAGD facility.

The most efficient Cogen case with the lowest fuel use for steam generation and GHG emissions was Case 3 that incorporated two 85

MWe gas turbines with HRSGs capable of duct burning. At a SOR of 3, that design could provide all of the steam and power demands for the facility, while potentially delivering about 2% of annual electricity demand on the public grid in Alberta.

Cogen Case 4 showed that the gas turbines could be run at 60% load factor and achieve about the same thermal efficiency as could be achieved at higher load factors. However, because there is less power and heat generated when running at the 60% load factor, more duct burning, and even some forced air-duct burning (equivalent to OTSGs) would be required to meet the SAGD steam demand. Nevertheless, this design could be attractive, if there is an interest in using the SAGD Cogeneration to provide a back up to non-dispatchable renewable power generation. To provide the backup power, the gas turbine output could be increased to 100% load factor and the HRSG duct burning or forced air-duct burning is reduced without affecting the steam generation.

The study shows that Cogen reduces system level GHG emissions. By assigning 390 kilograms (kg) CO_2 per megawatt-hour (MWh) to electricity and the remainder to oil production, it is possible to calculate the GHG intensity of oil sands crude production. In the Base Case with SOR of 2 to 4, the GHG intensity ranged from 52 to 101 kg CO_2 per barrel, about 2 to 4 times the GHG intensity associated with conventional oil recovery. With two 85 MWe Cogen facilities on similar SAGD facilities, the GHG emission intensity was reduced by 19% to a range of 42 to 82 kg CO_2 per barrel. However, these values are still 1.7 to 3.3 times higher than the GHG intensity associated with conventional oil recovery.

A range of assumptions for natural gas, carbon and electricity prices, and incremental capital costs were used to calculate the 20 year net present value (NPV) of the investment for the three Cogen cases relative to the Base Case, assuming a minimum of 10% annual return on the investment. The median values for all simulations showed a positive NPV in the range of $90M to $190M when compared to the Base Case. The economics were more positive at higher SOR than at lower, and more positive when the gas turbines were running at 100% load factor, than at 60% load factor. However, our assumptions may not have made sufficient allowances for how the back-up market would work and whether the premium that may be payable for generation capacity that provides backup for renewables could be reasonable. In all cases, gas and electricity prices and capital investments have the greatest impact on project economics.

This study is the first in a series of assessments that CESAR is planning to explore opportunities to reduce GHG emissions associated with SAGD operations and the electrical grid. A subsequent study will evaluate the potential impact of SAGD Cogen on the Alberta public grid, including the results of using SAGD Cogen to support the early retirement of power output from coal-fired power generation. The purpose of these two studies is to initiate a collaborative dialogue across all the sectors to reduce the system level GHG emissions in the province of Alberta.

1. Introduction

To generate electricity, Alberta relies on burning coal and natural gas, producing more than 46 million tonnes (Mt) of CO_2 per year (more than 11 tonnes per person). However, most of this thermal power generation uses technologies that capture only 30% to 50% of the fossil fuel energy into electricity. The rest of the energy is lost as waste heat, resulting in about 393 petajoules (PJ) per year being disposed of to either the atmosphere or cooling water.

In most jurisdictions in the world that rely heavily on thermal power generation, there are some industries that could use a proportion of the discarded heat energy or urban centres that would use this waste heat for district heating. Alberta is different as its oil sands industry is large enough to use the waste heat from electricity generation for oil sands crude production.

Steam Assisted Gravity Drainage (SAGD) is an oil sands technology that currently produces about 1 million barrels of oil sands crude per day (BPD). It requires 408 PJ of heat energy per year to make the steam for SAGD, generating about 24 Mt of CO_2 per year. This carbon footprint has been a central concern of those opposing oil sands development and pipeline projects that will bring oil sands products to export markets.

We need to explore the feasibility of integrating the SAGD and thermal electricity sectors in Alberta for the benefit of the environment and the economy. The time to do it is now since the Alberta government has set a 'best before' date on the province's carbon-intense, coal-fired generators. By 2020, 14% of their current capacity must meet a standard based on natural gas combined cycle power generation according to the federal regulations. The province has recently stated a desire to eliminate all coal power emission by 2030 while replacing two-thirds of the current coal generation capacity with renewables. Alberta's power generation infrastructure is at the cusp of a major transformation.

The default option for replacing coal infrastructure is to use natural gas-fired combined cycle plants. Certainly, these plants produce power with a lower carbon footprint than coal; however, about 50% of the fuel energy would still be discarded as waste heat. In contrast, a basic cogeneration facility discards at most 30% of the heat, with 70% or more being converted to useful power or heat.

Cogeneration is used in a number of oil sands operations today, but few if any have optimized cogeneration to provide both heat production for internal use and contribute base load and backup generation for the public grid. By doing so, SAGD facilities can not only meet their own needs for both heat and power, but provide reliable, base load, low-carbon power to the Alberta grid.

This study explores a cogeneration strategy by carrying out a detailed, techno-economic-environmental assessment of the impact of cogeneration on a 33,000 BPD SAGD facility. The study scope includes retrofitting one or two 85 MW Cogeneration units into SAGD projects having steam to oil ratios (SORs) from 2 to 4. The two cogeneration units were assumed to operate at 100% or ca. 60% load factor. The lower load factor would permit the gas turbines to ramp up their generation to back up renewable energy power generation when it is off-line.

A second study in this series, which is not part of this report, draws on the results of work presented here to create a techno-economic-environmental assessment that explores the potential of SAGD cogeneration to support the province's GHG objectives associated with both power generation and oil sands crude production.

2. Mass and Energy Flow in SAGD Cogeneration (Cogen)

2.1. The SAGD Process: an Overview

In Alberta, SAGD is the standard technology for oil sands crude production from reservoirs that are too deep for surface mining. It deploys a pair of horizontal wells to access the oil reservoir, where the upper well is for steam injection and the lower well is for production. High-pressure steam (at 100% quality) is injected into the upper well where it rises and condenses in the reservoir creating a steam chamber. The heating by the condensing steam reduces the viscosity of the crude oil so it flows easily in the reservoir.

The steam condensate and the crude oil form an emulsion that flows by gravity to the bottom of the chamber where the production well is located. There, an electrical submersible pump lifts the emulsion to the surface where it flows to a central processing facility (CPF) for oil treatment (see Figure 1). In the CPF the crude oil is separated from the produced water and the produced water is treated to remove any residual crude oil, hardness and silica. The water is treated so it can be used as boiler feed water for generating the high-pressure steam needed to maintain SAGD production.

Reservoirs used for SAGD production can vary in quality, with some requiring more or less steam per barrel of produced oil sands crude. Steam requirements are expressed in barrels of cold water equivalent of steam per barrel of produced oil sands crude (i.e., steam-to-oil ratio (SOR)). Typically, SOR values range from 2 to 4, with 3 being the average of current SAGD production.

In most SAGD projects, once through steam generators (OTSG) fired by natural gas are deployed for steam generation. Due to the significant amount of contaminants in the recycled water and the need to avoid excessive fouling of the boiler tubes, the boiler feed water is only treated pure enough to produce 77% quality steam. The wet steam is sent to a vapour/liquid separator where 100% quality steam is produced for injection into the reservoir. Of the remaining 23%, ~2% is used for utility steam, ~ 7% is blowdown sent to a disposal well to dispose of hardness and silica, and the remaining 14% is recycled back into the process. The heat in the blow down is extracted before it is sent to a deep well for disposal. Saline make up water is brought in to be treated to replenish the water retained in the reservoir and lost to blow down.

The electricity requirement for SAGD production using OTSG is met by importing electricity from the Alberta public grid. But there are some operators that have installed natural gas-fired gas turbines to provide both heat and power (i.e. cogeneration) for SAGD operations. The hot combustion gas exiting from the gas turbine can be fed to a heat recovery steam generator (HRSG) that can be supplemented with produced gas and more natural gas to generate additional steam. This process is often referred to as duct burning (DB).

If even more steam is required, a fan can be added to the HRSG in order to deliver supplemental combustion air to complement the oxygen in the gas turbine exhaust for additional combustion. In this duct-burning mode using supplemental air, the HRSG operates like an OTSG. In this report, we refer to that as forced air-duct burning (FA-DB). Currently this is not done in Alberta, since OTSG are the dominant technology.

In this study, we explore the energy efficiency, environmental and economic implications of various strategies for providing the heat and power needs for a 33,000 barrels-per-day (BPD) SAGD project, including their contributions to the Alberta electrical grid.

2.2. Heat and Power Demand for a Typical SAGD Facility at Various SOR

This study has used standard engineering design and calculations, physical data, mathematical formulae and conversions factors.

The material and heat balances for a typical 33,000 BPD SAGD facility are provided in Table 1, including the power demands at SOR ranging from 2 to 4. These balances were calculated based on the block flow diagram in Figure 1.

Our calculated values for a SOR of 3 were compared with the published results for a typical 33,000 BPD SAGD facility as defined by COSIA[1]. The numbers were in agreement within 5%. As SOR values increased from 2 to 4, the higher boiler feed water requirements increased the heat and power requirements needed to generate

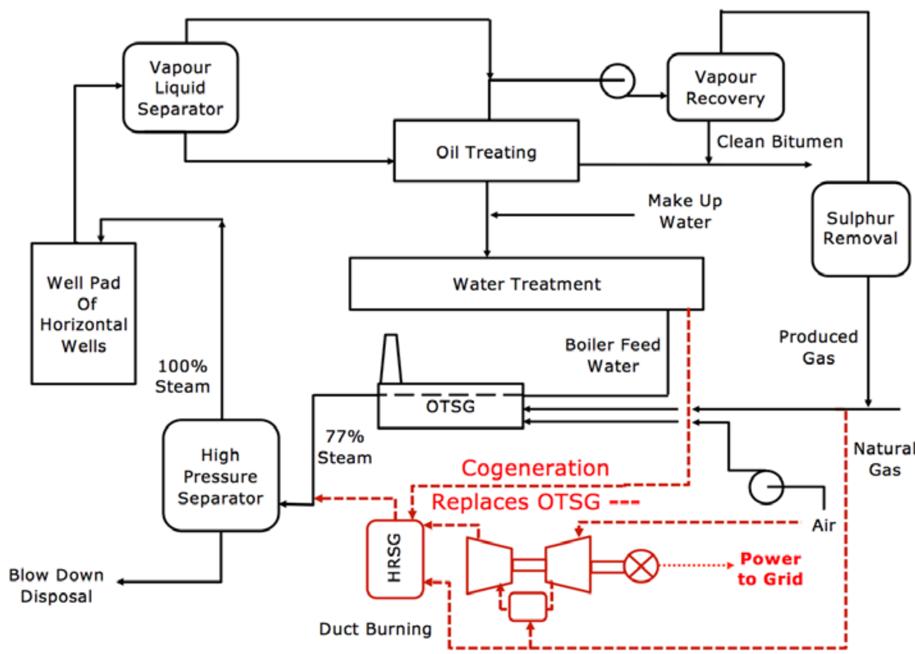


Figure 1. A generic Steam Assisted Gravity Drainage (SAGD) central processing facility. Note that steam can be generated by either once through steam generators (OTSG) or by cogeneration of electricity and steam using a combination of gas turbine(s) (GT) and heat recovery steam generators (HRSG) as shown in red. See Figure 3 for more details on Cogeneration.

1 Canada Oil Sands Innovation Alliance (COSIA), 2014. New high efficiency industrial Gas Boiler Challenge. Oct. 8, 2014

Table 1. Assumed and calculated parameter values associated with a typical (non-cogeneration) 33,000 BPD SAGD operation

	Parameter	Units	Steam : Oil Ratio 2	3	4
SAGD Output	Daily Oil Production	BPD	33,000	33,000	33,000
	Produced Gas (HHV)	GJ/d	1,675	1,675	1,675
Heat Supply & Demand	Heat Demand	GJ/d	22,275	33,413	44,550
	Efficiency of Heat Production (HHV)[1,3]	%	78%	78%	78%
	Total Fuel Required (HHV)[3]	GJ/d	28,423	42,634	56,845
	Natural Gas Required (HHV)[2,3]	GJ/d	26,748	40,959	55,170
	Total GHG Emissions from Combustion[4]	t CO_2e/d	1,488	2,190	2,893
	GHG Emission from Combustion per Barrel	kg CO_2e/bbl	45.1	66.4	87.7
Water Requirement	100% Quality Steam Required	BPD CWE[5]	66,000	99,000	132,000
	Steam Quality from OTSG (310C, 10 MPa)	%	77%	77%	77%
	Boiler Feed Water	BPD CWE[5]	85,714	128,571	171,429
Power Demand	Production lifting	MW	1.63	2.17	2.71
	Production flow in Well	MW	0.01	0.01	0.01
	Well to Central Processing Facility	MW	0.26	0.45	0.69
	BFW to HRSG	MW	3.96	5.95	7.93
	Oil treatment	MW	0.05	0.06	0.07
	Water Treatment	MW	0.20	0.29	0.39
	Sales Oil	MW	0.13	0.13	0.13
	Glycol Loop[3]	MW	0.10	0.15	0.21
	Small pumps, etc	MW	0.83	1.25	1.67
	Vapour Recovery Unit	MW	1.96	1.96	1.96
	Misc Use	MW	1.27	1.90	2.53
	OTSG Blowers[3]	MW	2.14	3.21	4.29
	Total Power Demand[3]	**MW**	**12.53**	**17.53**	**22.58**

Notes:
1. Efficiency of Once Through Steam Generator (OTSG).
2. Calculated as Total Fuel Required Minus Produced Gas.
3. Values will vary with the addition of cogeneration.
4. Assumes 49 kg CO_2/GJ (NG), 99 kg CO_2/GJ (PG).
5. CWE = Cold Water Equivalent.

more steam and hydraulically move the additional water and steam through the SAGD central processing facility. This accounts for the greater heat and power demands with the higher SOR (Table 1).

The central processing facility deploying cogeneration is similar to a facility using OTSG with the exception of heat and electricity generation. Instead of using an OTSG for steam generation, steam comes from a HRSG fed by the gas turbine, and by ‘duct burning’ of additional natural gas (up to 40% of the gas feed to the gas turbine) in the HRSG. As a result, cogeneration:

- Uses less natural gas for steam production as the HRSG benefits from the hot gas turbine exhaust. The steam will be produced from the sensible heat of the gas turbine exhaust and duct burning. Also, duct burning is more efficient than conventional combustion as the gas turbine exhaust contains about 15% hot oxygen (greater than 500o C) for duct burning, whereas in OTSG combustion air is pre-heated to no more than 100o C.
- Does not require a blower to introduce air for duct burning up to 40% of natural gas consumed by the gas turbine; hence, there is a lower power requirement at the same SOR.
- Compared with conventional boilers, the duct burner system essentially achieves almost a 100% heat energy efficiency operation for thermal service.
- Uses more natural gas than OTSG in order to generate power in the gas turbine for site use and export, but resulting in fuel savings in other locations (e.g., power generation using natural gas combined cycle) that would otherwise be generating the power now being generated by SAGD Cogen.

2.3. The Carbon intensity of the Alberta Grid

Users of electricity in Alberta can either draw power from the public grid or produce it themselves. Power that is produced and consumed without exporting to the public distribution or transmission systems is called “Behind the Fence” (BTF) generation. Facilities with BTF generation can either be connected to the public grid or not. If the BTF generation facilities are connected to the public grid they can either sell their excess power into the public grid for use by others, or import power from the grid to make up for a shortfall that may occur in their own power production.

Figure 2 provides an estimate of electricity generation in Alberta in 2014, segregated into produced and used BTF generation, and that available on the public grid. For each, we provide a break down into the technologies and fuel sources used for generation. Since each fuel source / technology combination has a characteristic GHG intensity (kg CO_2e/MWh), it is possible to calculate the average GHG intensity of the public grid and BTF generation. The GHG intensity of cogeneration was assumed to be 390 kg CO_2/MWh to match what was used in the remainder of the analysis. This allows for comparisons of the grid with and without additional generation from cogeneration later in the report. As the majority of the BTF generation comes from natural gas and biomass cogeneration, it had a combined GHG intensity of 373 kg CO_2e/MWh. However, over 60% of the public grid generation in 2014 came from coal[2], resulting in an estimated GHG intensity of the public grid of 762 kg CO_2e/MWh[3], more than double the intensity of BTF generation.

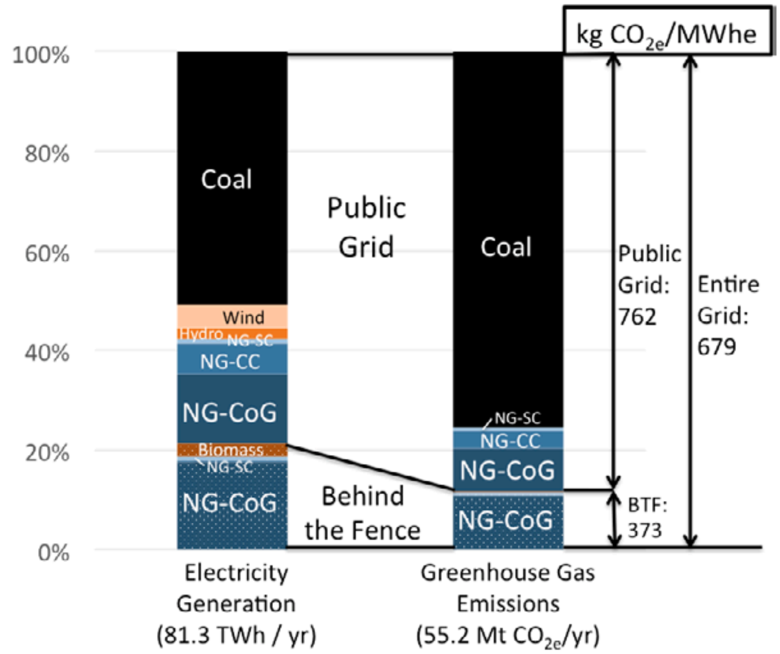


Figure 2. Electricity generation and GHG emissions for different generation technologies used on the public grid and for Behind the Fence (BTF) generation. The data used for this analysis are from 2014. NG, natural gas; CC, combined cycle; CoG, cogeneration; SC, Single cycle.

Therefore, while coal accounted for about 50% of total power generation in the province in 2014, it contributed 75% of the GHG emissions from electricity production. The overall efficiency of the public grid depicted in Figure 2 was estimated to be 39.6% (data not shown).

2.4. Gas Turbine Performance

For this study we modeled the incorporation of one or two GE Frame 7E gas turbines into each 33,000 BPD SAGD facility. These cases were chosen because this unit has a track record for use in SAGD facilities.

2 Alberta Electric Systems Operator, AESO 2014 Annual Market Statistics. February 19, 2015

3 EDC Associates Ltd, Trends in GHG Emissions in the Alberta Electricity Market. May 2, 2013

At a SOR of 3, the heat from one gas turbine running at 100% load factor, plus the heat from duct burning (without forced air), is sufficient to provide 50% of the SAGD heat demand[4]. Therefore, two 85 MW gas turbines running at 100% load factor are sufficient to meet all of the steam requirements for this facility.

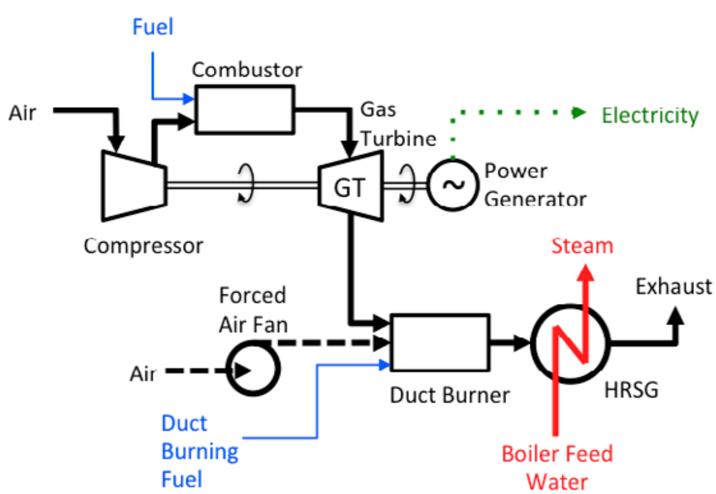


Figure 3. Schematic diagram of a cogeneration system. The system includes a gas turbine power generator, duct burning and steam production through Heat Recovery Steam Generator (HRSG). Air (black, thick line) is compressed for the gas turbine and, if additional combustion air is needed (black, thick dashed line), it can also be provided to the duct burner. Fuel (blue, thin line) is used to heat the compressed air that expands to drive the gas turbine (GT) and to provide supplemental heat in the duct burner (up to 40% of GT fuel without additional forced air). Electricity (green, dotted line) is produced by the power generator, and steam (red, thick line) is produced by the HRSG.

The components of a co-generation system and the basic principles for its operation are illustrated in Figure 3. This schematic shows how the rotating gas turbine provides both power and hot depleted air that is used to make steam in a HRSG. Additional heat can be made by duct burning without (more efficient, but limited capacity) or with the addition of forced air (forced air-duct burning).

To understand the capabilities of the gas turbine for power and heat production, we first assessed its performance in the absence of any duct burning, for a range of load factors defined as a percentage of the 85 MWe gas turbine rated electrical output. The data are provided in Figures 4 & 5.

While fuel use in terms of higher heat value (HHV) and lower heat value (LHV) declines with lower load factor, this decline is more gradual than the decline in load factor; so at lower load factors, proportionately more fuel is being used to generate each unit of power output (Figure 4A). Similarly, as the load factor is decreased, the amount of fuel energy required per MWh increases, making the electricity production less efficient and the heat rate[5] higher (Figure 4B).

At load factors greater than 60%, the overall efficiency of a Cogen unit (without duct burning) remains relatively constant (Figure 4B).

4 The data used in this study were provided by General Electric, the manufacturer of the Frame 7E gas turbine.

5 The heat rate is the amount of energy in the fuel (in GJ) per MWh of electricity generated.

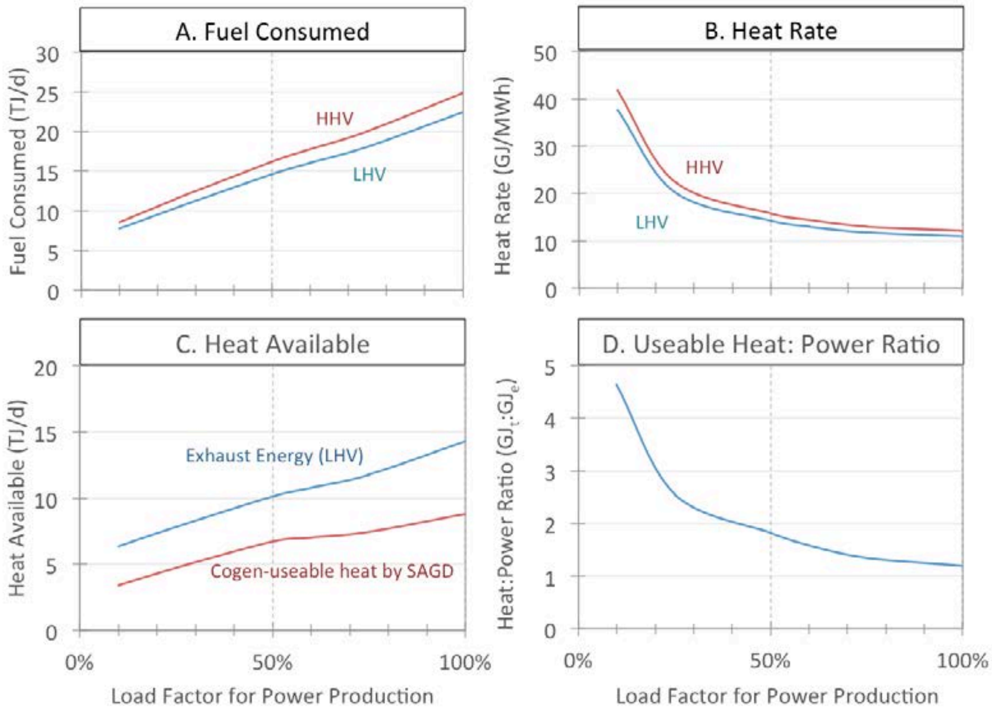


Figure 4. Performance of a GE 7E gas turbine with a heat recovery steam generator (HRSG) and no duct burning. Details are provided for fuel consumed (A), heat rate (B), heat available (C) and useable heat: power ratio (D)

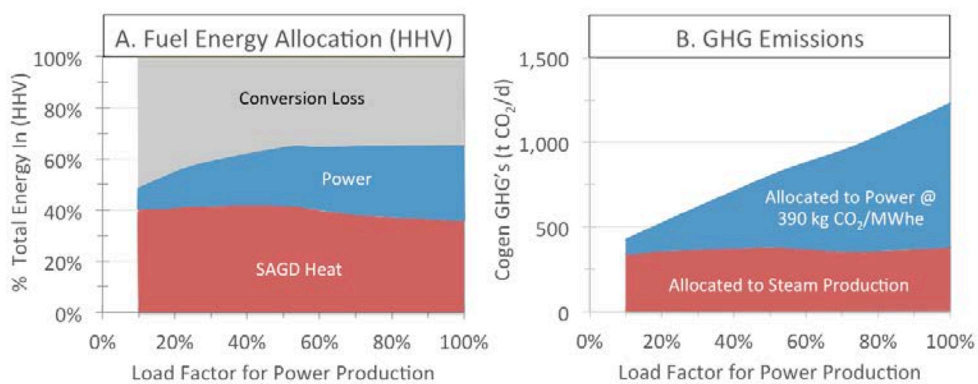


Figure 5. Fuel Energy Allocation (A) and GHG Emissions (B) for an 85 MWe GE 7E GT with HRSG (but no duct burning) over a range of load factors. Fuel energy was allocated to power generation, useable steam for SAGD and conversion losses, while GHG emissions were allocated to power generation (assumes 390 kg CO_2/MWh) and steam production.

However, below 50% load factor, the efficiency of the system declines, accounting for the fact that most Cogen operators do not run the units at less than a 50% load factor.

The heat in the gas turbine exhaust and the amount of energy used for steam production in the HRSG is shown in Figure 4C. The difference between the two lines is the unused heat in the HRSG exhaust (Figure 3). Note that these plots do not include energy input or heat recovery from duct burning or forced air-duct burning. The resulting useable heat to power ratio of the Cogen unit increases with decreasing load factor as shown in Figure 4D.

From these data, it was possible to calculate the fuel energy allocation (in HHV) between power, useable heat and conversion losses at load factors from 10% to 100% (Figure 5A). As the load factor decreases, the proportion of energy going into electricity production decreases, but the proportion used for steam generation increases.

Figure 5B shows the GHG emissions (tonnes CO_2e/d) from an 85 MWe Cogen unit (without duct burning) that is attributed to power generation versus heat production when the power generation is assigned a GHG intensity of 390 kg CO_2e/MWh (See Box below for details). As the load factor decreases, the GHG emissions attributed to power production decrease linearly, and the GHG emissions attributed to heat production are relatively constant(Figure 5B). However, useable heat declines more precipitously when the load factor drops below 50% (Figure 4C).

Assigning GHGs to Cogen Power

Cogeneration produces electricity and steam together in one facility with one exhaust stack. The efficiency of SAGD cogeneration system is significantly better than generating the same products in separate facilities since the hot exhaust gases from an electricity producing gas turbine are used to generate steam in the Heat Recovery Steam Generator (HRSG).

The Alberta Specified Gas Emission Regulations (SGER) contain an allocation method that specifies that the stand-alone boiler is 80% efficient based on thermal energy (HHV), and the balance of actual emissions are allocated to power generation. SGER deems export power to have GHG intensity of 418 kg/MWhr for facility reporting and compliance calculations. If the actual power emissions from cogeneration are lower than 418 kg/MWhr a benefit is recognized in GHG compliance. Conversely, a penalty is applied if over 418 kg/MWhr. However, we understand that new policies are being developed to lower this number to around 390 kg CO_2e/MWh.

For this study, 390 kg CO_2e/MWh has been used for the GHG intensity of power generation and the remainder of the GHG emissions are attributed to steam production. All GHG emissions from fuel used in duct burning, forced air-duct burning, or OTSG steam production have been assigned to steam production.

2.5. Modeled Cases for SAGD Facilities

Using the data and assumption described above, four different SAGD facilities were modeled in this study that are applicable both to greenfield projects or retrofitting operating SAGD projects with their OTSG put on stand-by:

No Cogen (or Base Case). A SAGD facility producing 33,000 BPD of oil sands crude using natural gas-fired OTSG and importing power from the public grid. The SOR were varied from 2 to 4 and for each SOR, the natural gas and power requirements were calculated.

One gas turbine @ 100% load factor per SAGD. One gas turbine with HRSG operating at 100% load factor. The HRSG includes duct burning to a maximum of 40% of the fuel supply to the gas turbine, with the remainder of steam produced via OTSG or HRSG equipped for forced air duct burning (OTSG and forced air-duct burning were assumed to have similar efficiency for fuel use and steam generation). The power demands for the SAGD facility are met by the gas turbine, with excess power exported to the public grid.

Two gas turbines @100% load factor per SAGD. Two gas turbines with HRSGs operating at 100% load factor. The HRSGs include duct burning to a maximum of 40% of the fuel supply to the gas turbines, with the remainder of steam produced via HRSG forced air-duct burning. The power demands for the SAGD facility were met by the gas turbines, with excess power exported to the public grid.

Two gas turbines @ 60% load factor per SAGD. Two gas turbines with HRSGs operating at 60% load factor in order to also provide reserve capacity on the grid to back up renewables (e.g. the gas turbines can be ramped up to 100% load factor when the renewables are not exporting electricity to the grid). The HRSGs include duct burning to a maximum of 40% of the fuel supply to the gas turbines, with the remainder of steam produced via HRSG forced air-duct burning. The power demands for the SAGD facility were met by the gas turbines, with excess power exported to the public grid.

3. Model Results for Mass and Energy Flow in SAGD Cogen

3.1. Heat and Power Demand for SAGD

Using the parameters defined in the previous section, and assuming different contributions from cogeneration, the heat and power demands of a 33,000 barrels-per-day SAGD facility were calculated running at steam-to-oil ratio from 2 to 4. While heat demand varied only with SOR, power demand was impacted by both SOR and the role of cogeneration (Figure 6).

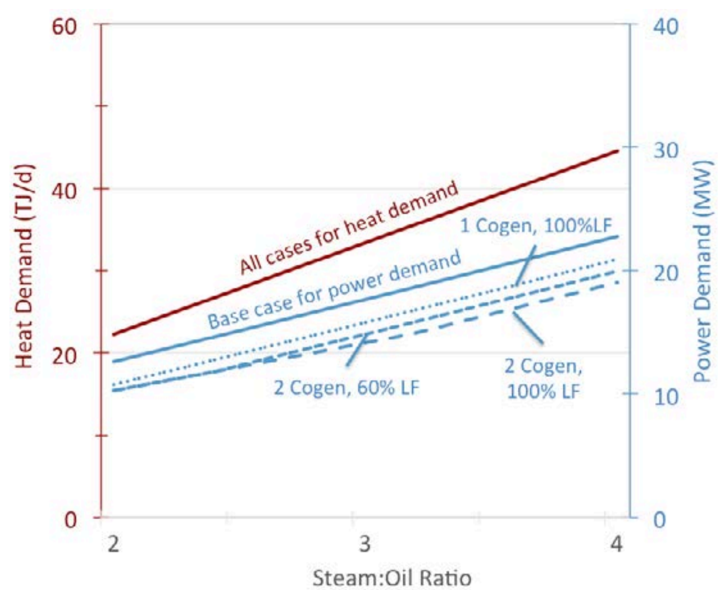


Figure 6. Heat (red axis and line) and power (blue axis and lines) demands in the four case studies.

The SOR causes the power demand to vary because, as more steam is required at higher SOR, more energy is required to pump the greater amount of boiler feed water and produced water around the site, and more fan power is needed to supply combustion air to the OTSGs in the Base Case or to the forced air-duct burning in the other cases.

Adding cogeneration to a site reduces the electrical demand from that site due to the fact that any steam produced from a HRSG does not require a large fan to force the air into the steam generator. The gas turbine forces the air into the HRSG making the blower fans that are used in OTSGs unnecessary.

At a SOR of 2, power demands of the 60% and 100% load factors of two Cogen cases are the same. This is because all of the steam for both cases is produced from the gas turbine waste heat and duct burning, and fans are not needed to provide combustion air in the HRSG.

As the SOR increases and more heat is required, the 60% load factor case is unable to produce enough heat with just the gas turbines and duct burning, so large fan units are required to provide combustion air for forced air-ductburning, thus increasing the power demand in the 60% load factor case compared to the 100% load factor case.

3.2. Load Factor Impacts on Fuel Use, Useable Heat and Power Production

Drawing on the previous data for gas turbine performance, and combining it with a knowledge of SAGD heat and power demands at different SORs, a series of plots can be generated describing fuel use (Fig. 7), useable heat (Fig. 8), generated power (Fig. 9) and GHG emissions (Fig 10) for a 33,000 BPD SAGD facility with one or two 85 MWe cogeneration systems operating either at 100% load factor or 60% load factor.

Equipping a 33,000 BPD SAGD operation with only one Cogeneration system provides all the power needs but does not produce enough heat to meet the steam requirements for SAGD, even when ‘duct burning’ using a HRSG is incorporated into the design (Figure 7A). The additional heat demand is typically met by once through steam generators (OTSGs) (Figure 8).

With two cogeneration units per SAGD, cogeneration can provide all the power and all the heat requirements, especially at 100% load

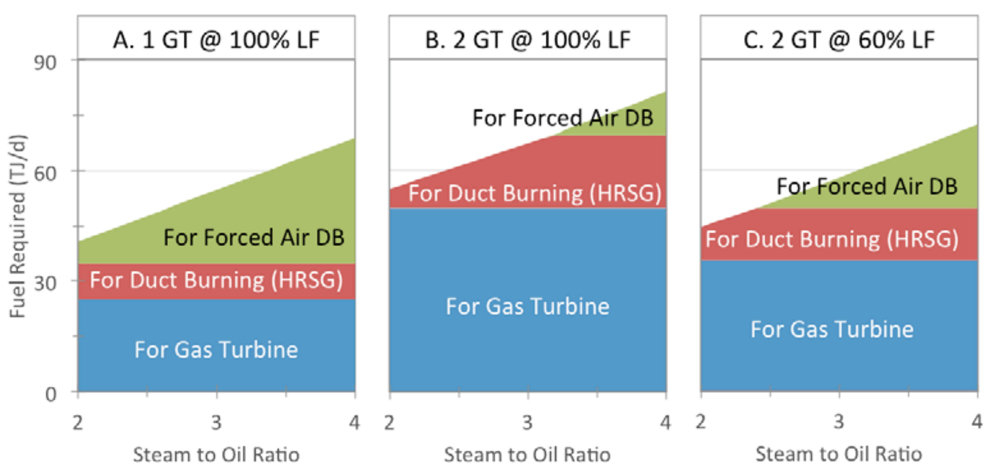


Figure 7. Fuel required by a 33,000 BPD SAGD facility with one (A) or two (B, C) 85 MWe capacity cogen units running over a range of SORs. Charts A & B show results associated with running the cogen units at 100% load factor while Chart C assumes the Cogen units are at 60% load factor so they can also provide a backup for renewables. Details are also provided regarding how the fuel is used.

factor (Figure 7B, 8B). The 100% load factor demands higher fuel consumption than two units operating at 60% load factor (Figure 7C, 8C), but does not require forced air-duct burning at SOR values of less than about 3.2 (Figure 7B, 8B). This is because producing additional electricity consumes additional fuel, and creates additional heat. The least efficient form of heat production is from

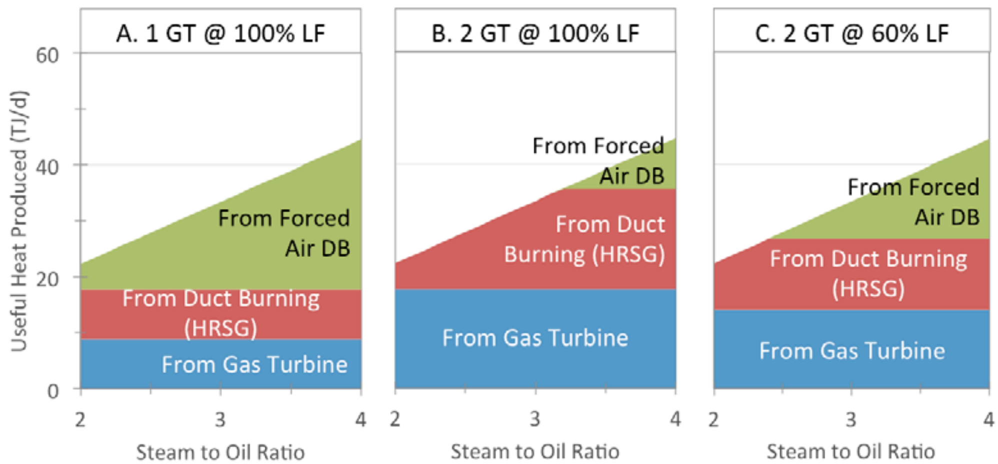


Figure 8. Useful heat production by a 33,000 BPD SAGD facility with one (A) or two (B, C) 85 MWe capacity Cogen units running over a range of SORs. Charts A & B show results associated with running the Cogen units at 100% load factor while Chart C assumes the Cogen units are at 60% load factor so they can also provide a backup for renewables. The sources of the heat within each Cogen system are also provided.

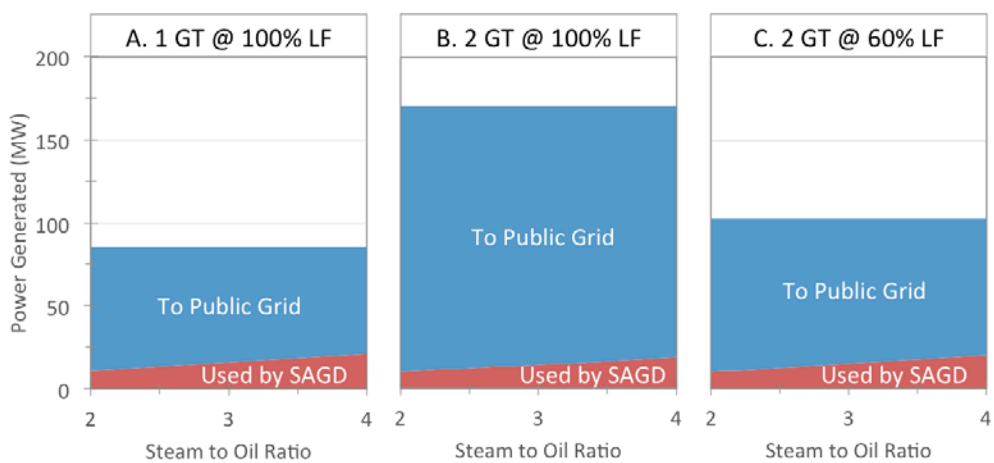


Figure 9. Power generated from a 33,000 BPD SAGD facility with one (A) or two (B, C) 85 MWe capacity Cogen units running over a range of SORs. Charts A & B show results associated with running the Cogen units at 100% load factor while Chart C assumes the Cogen units are at 60% load factor so they can also provide a backup for renewables. The allocation of the generated power between SAGD use (behind the Fence) and the public electrical grid is also shown.

forced air-duct burning in the HRSG (equivalent to OTSG), so operating at 100% load factor is more efficient than operating at 60% load factor.

When two cogeneration units are deployed per SAGD facility (Figure 9B), rather than one (Figure 9A), the contribution of electricity to the public grid more than doubles. This is because the SAGD demand for power BTF actually declines with cogeneration, since there is a lower demand for large fan units. Even in the 60% case (Figure 9C), the electricity use BTF is higher at SOR greater than 2.5 due to the additional forced-air duct burning required.

The resulting GHG emissions from the three cases are provided in Figure 10. By assigning a GHG intensity of 390 kg CO_2e/MWh to electricity generation from cogeneration, it is possible to calculate the GHG emissions that are assigned to the heat from the gas turbine. The combustion emissions associated with duct burning and forced air-duct burning are allocated to the heat demand for the SAGD facility (Figure 10).

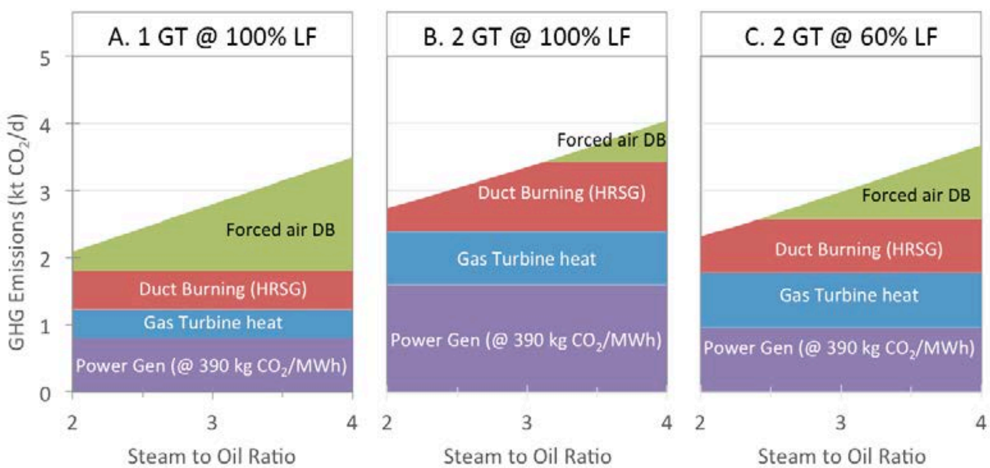


Figure 10. GHG emissions from a 33,000 BPD SAGD facility with one (A) or two (B, C) 85 MWe capacity Cogen units running over a range of SORs. Charts A & B show results associated with running the Cogen units at 100% load factor while Chart C assumes the Cogen units are at 60% load factor so they can also provide backup for renewables. The emissions are allocated to power generation (assuming 390 kg CO_2e/MWh), gas turbine heat, duct burning and forced air duct burning, as needed to meet total SAGD steam demand.

3.3. Greenhouse Gas Emissions and Emissions Intensity of Oil Sands Crude Production

When the GHG emissions from the four cases were expressed per barrel of oil sands crude produced, values for emission intensity were obtained as shown in Figure 11. At any given SOR, the GHG emissions intensity is highest in the no cogeneration case (Base Case), as it obtained its electricity needs from Alberta's public grid (grid intensity of 762 kg CO_2e/MWh, Figure 2).

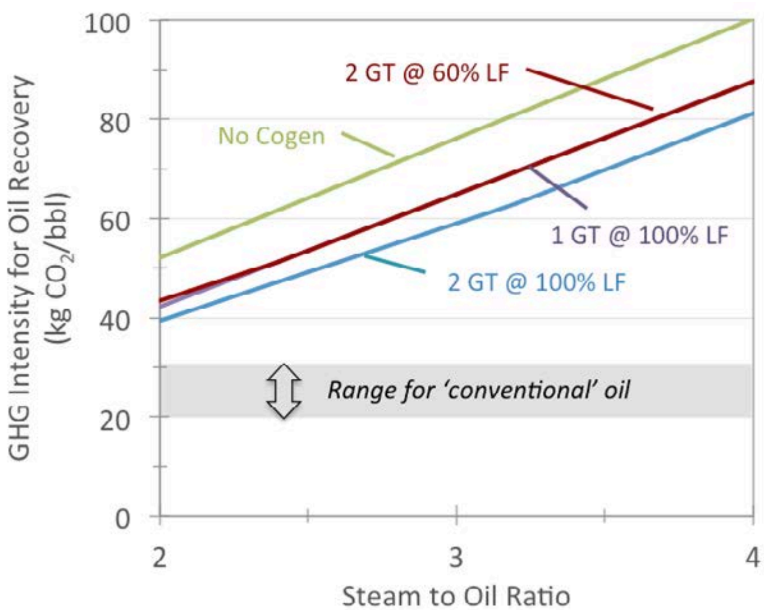


Figure 11. GHG intensity for oil recovery for the four case studies. Note that Cogen power was assumed to have a GHG intensity for power of 390 kg CO_2e/MWh.

All of the Cogen cases show GHG intensities that are lower than the Base Case. With one gas turbine (GT) per SAGD facility running at 100% or two gas turbines running at 60% load factor, the GHG intensities are 12% to 15% lower. In the case of two gas turbines per SAGD running at 100% load factor, the GHG intensities are 19% to 23% lower than the Base Case (Figure 9) over the SOR range of 4 to 2.

Despite these substantial reductions in the estimated GHG intensity of SAGD oil sands crude production from Cogen, the estimated intensities are still much larger than the range for conventional oil (shaded region in Figure 9). For comparison, at a SOR of 3, the Base Case has a GHG intensity of about 76 kg CO_2e/barrel, approximately three times the GHG intensity of conventional oil production.

However, it is important to note that these calculations only give the recovery of oil sands credit for Cogen's (a) lower energy use and GHG footprint associated with SAGD steam generation, and (b) lower electricity demand and using the lower GHG intensity of the on-site power generation. It does not consider the benefits of exporting low GHG-intensity Cogen electricity to the province's electrical grid. To do that requires a system level assessment that will be carried out in Layzell et al. (2016b).

4. The System Level Implications for Energy and Carbon Flow

4.1. Sankey Diagrams

Energy systems are complex, especially if one is trying to understand and communicate the interactions between very different energy system sectors. This is certainly the case in the present study, given the scale of cogeneration being explored. Heat and power are not only being generated for Behind-The-Fence (BTF) use in oil sands operations, but the SAGD cases described here have the potential to supply the public grid with many times the amount of power that is generated for use BTF. To see the energy flows in both sectors, they need to be brought together.

Sankey diagrams[6] are often used to depict energy flows, and can bring together multiple sectors and forms of energy. In a Sankey diagram, the width of the lines is proportional to the flow of energy in that part of the energy system. Since energy can neither be created, nor destroyed, the diagrams are beneficial in visually representing energy inputs, outputs, conversion efficiency and losses.

Figures 12, 13 and 14 each show a pair of Sankey diagrams depicting two different strategies for producing 33,000 BPD of oil sands crude with a SOR of 3, and the corresponding amount of electricity to the public grid. The Sankey diagram on the left of each figure illustrates one of the three cogeneration case studies which exports power to the public grid, while the diagram on the right is the Base Case (no Cogen), where the BTF power demands are met by importing the similar amount of electricity generated by the 2014 public grid (Figure 2).

The bar graphs associated with each Sankey diagram shows the total combustion-based GHG emissions and the relative contributions to those emissions from each part of the energy system. A GHG intensity of 762 kg CO_2/MWh was used for power from the public grid while a value of 390 kg CO_2/MWh was used for power generation by Cogen.

6 Named after Irish Captain Matthew Sankey, who used this type of diagram in 1898 to show the energy efficiency of a steam engine (see https://en.wikipedia.org/wiki/Sankey_diagram).

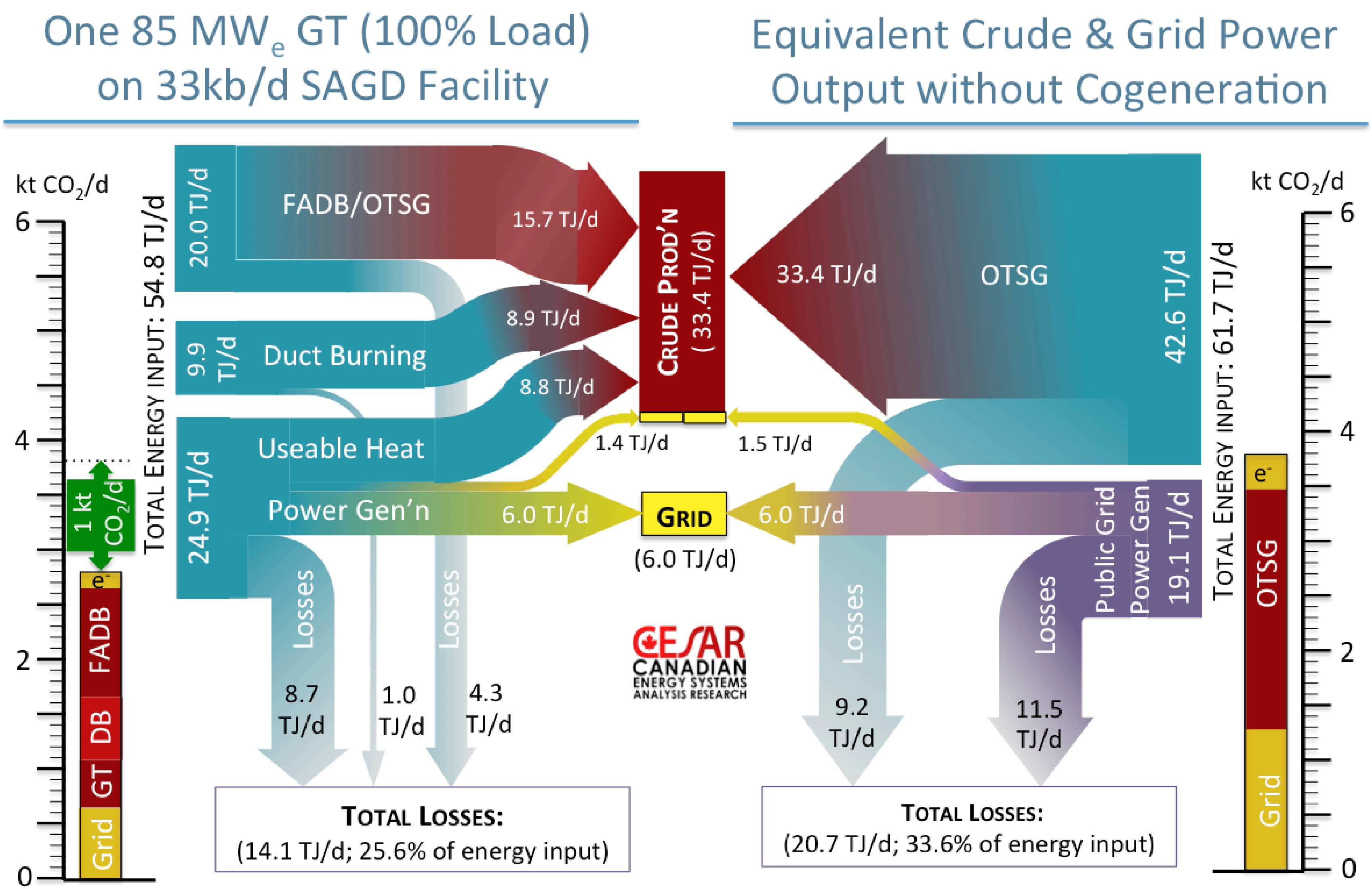


Figure 12. The effect of one 85 MWe gas turbine with cogeneration running at 100% load factor per 33,000 BPD SAGD facility on the system level flows of energy (Sankey diagrams) and GHGs (bar charts). The right side of the chart shows the equivalent crude and grid power output without cogeneration, so all electricity requirements are provided by the public grid.

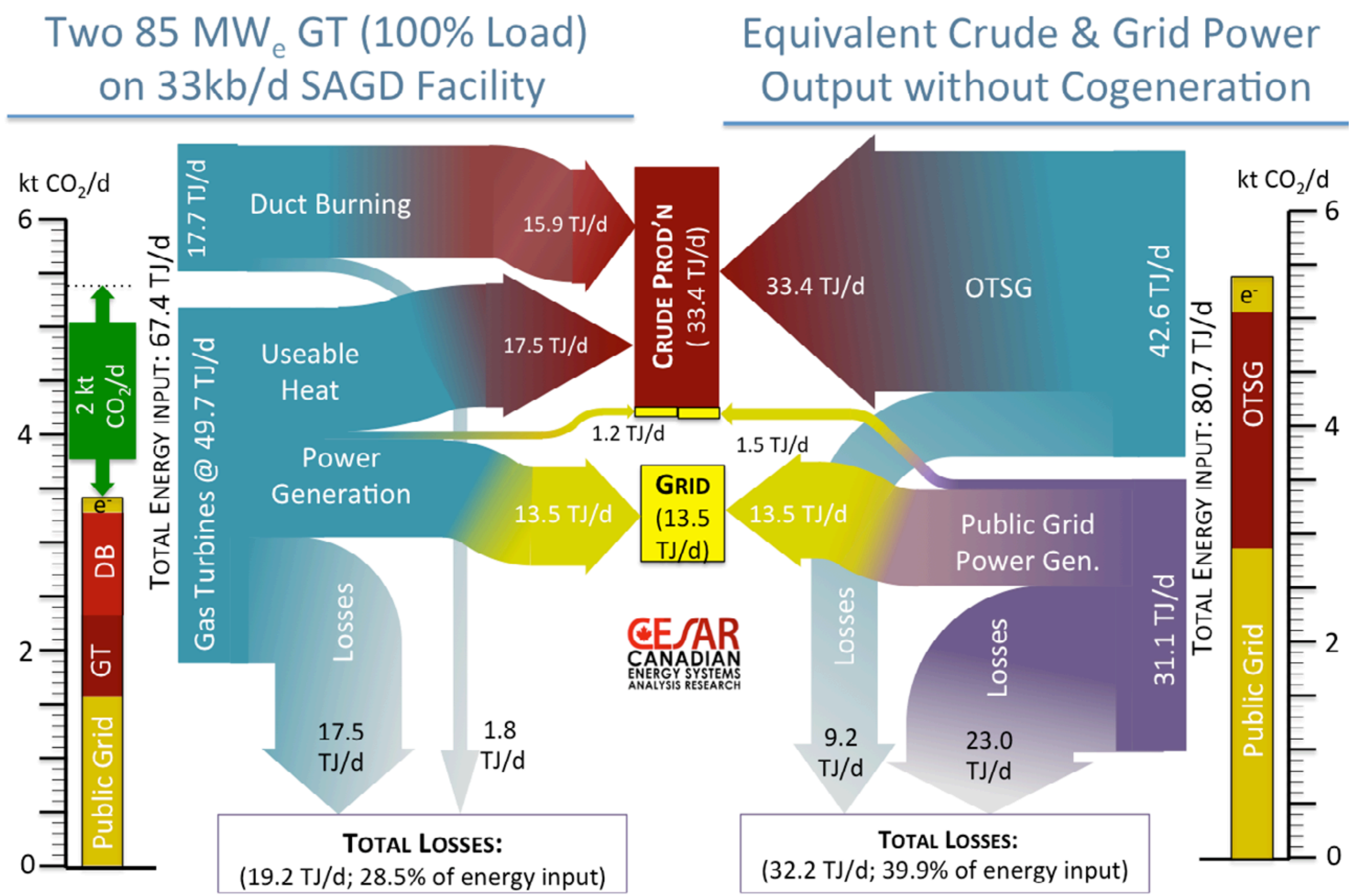


Figure 13. The effect of two 85 MWe gas turbines with cogeneration running at 100% load factor per 33,000BPD SAGD facility on the system level flows of energy (Sankey diagrams) and GHGs (bar charts). The right side of the chart shows the equivalent crude and grid power output without cogeneration, so all electricity requirements are provided by the public grid.

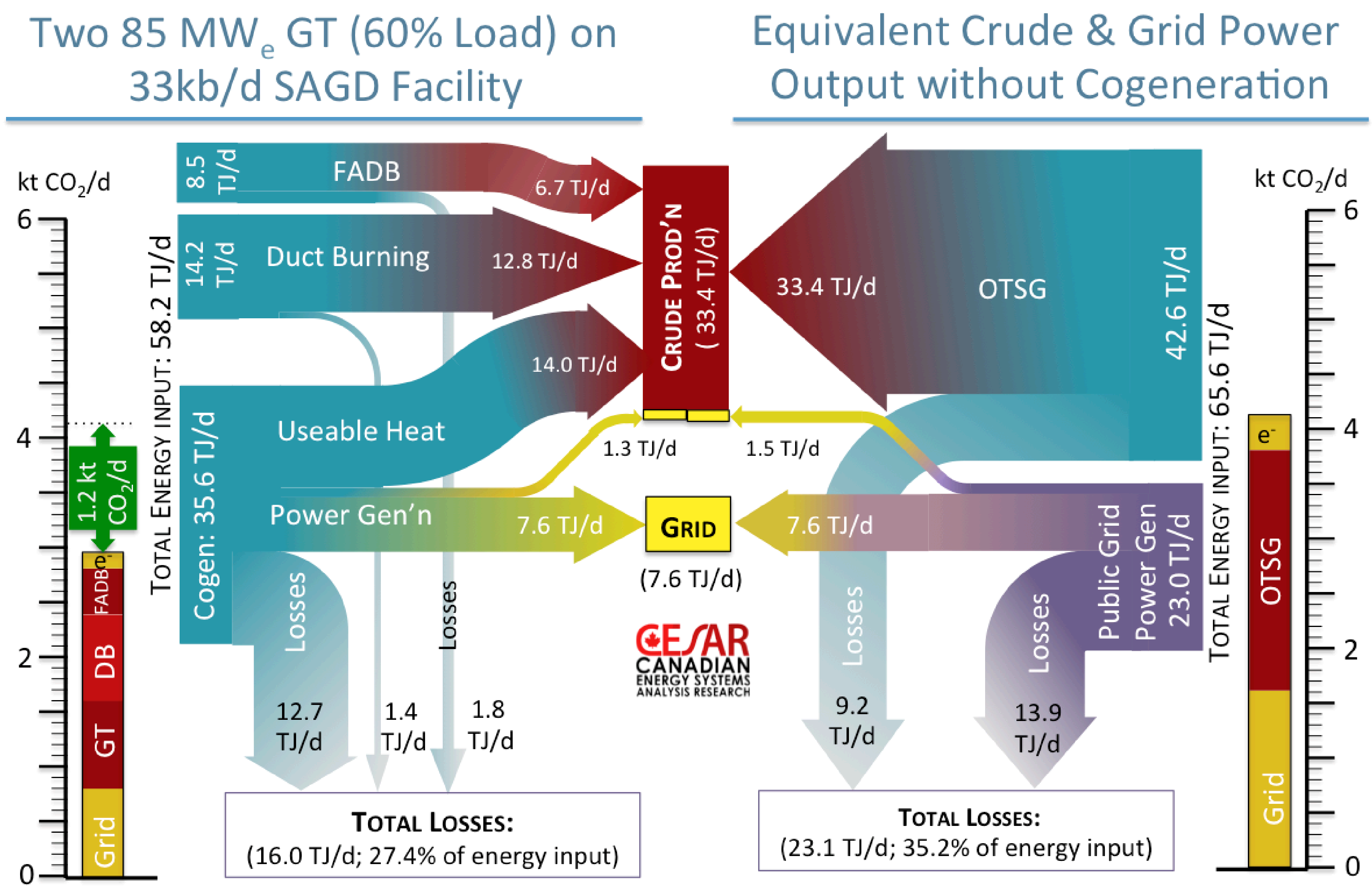


Figure 14. The effect of two 85 MWe gas turbines with cogeneration running at 60% load factor per 33,000BPD SAGD facility on the system level flows of energy (Sankey diagrams) and GHGs (bar charts). The right side of the chart shows the equivalent crude and grid power output without cogeneration, so all electricity requirements are provided by the public grid.

4.2. Case Study Comparisons for Energy Demand, Conversion Losses and GHG Emissions

In the case of one 85 MWe gas turbine (GT) at 100% load factor, all the heat and power demands are met for SAGD, and an additional 6 terajoules per day (TJ/d) of power can be put on the grid (Figure 12, Table 2). When compared to delivering the same output in a SAGD system without Cogen (power provided by the 2014 public grid), the Cogen-based system uses 11.2% less total energy input (54.8 TJ/d versus 61.7 TJ/d), has 32% lower conversion losses (14.1 versus 20.7 TJ/d) and produces 26% lower GHG emissions (2,800 vs. 3,800 tonnes (t) CO_2/d).

The energy and environmental benefits are even greater in the case study that considered two 85 MWe GT at 100% load factor per SAGD facility. In this case, (Figure 13, Table 2), the power provided to the grid is more than two times that of the first case (13.5 TJ/d) (Figure 13, Table 2). When compared to delivering the same output in a SAGD system without Cogen (power provided by the 2014 public grid), the Cogen-based system uses 16.5% less total energy input (67.4 vs.

Table 2. Results summary of case study comparison. In the Base Case (no cogeneration), the values for power to grid are set to be equal to that from the corresponding cogen case, but the electricity is assumed to come from the AB public grid with a GHG intensity as shown in Figure 2. This table summarizes the results from Figures 12-14.

Case Study	Parameter	Cogen Case	Base Case	% Improvement
One GT on 33 kBPD SAGD, running at 100% load factor	Power to Grid (TJ/d)	6.0	6.0	--
	Total Energy Input (TJ/d)	54.8	61.7	11.2% lower
	Conversion Losses (TJ/d)	14.1	20.7	31.9% lower
	GHG Emissions (t/d)	2,800	3,800	26.3% lower
Two GT on 33 kBPD SAGD, running at 100% load factor	Power to Grid (TJ/d)	13.5	13.5	--
	Total Energy Input (TJ/d)	67.4	80.7	16.5% lower
	Conversion Losses (TJ/d)	19.2	32.2	40.4% lower
	GHG Emissions (t/d)	3,400	5,400	37.0% lower
Two GT on 33 kBPD SAGD, running at 60% load factor	Power to Grid (TJ/d)	7.6	7.6	--
	Total Energy Input (TJ/d)	58.2	65.6	11.3% lower
	Conversion Losses (TJ/d)	16.0	23.1	30.7% lower
	GHG Emissions (t/d)	2,950	4,150	28.9% lower

80.7 TJ/d), has 40.4% lower conversion losses (19.2 vs. 32.2 TJ/d) and produces 37% lower GHG emissions (3,400 vs. 5,400 t CO_2/d).

Finally, In the case of two 85 MWe GT at 60% load factor, all the heat and power demands are met for SAGD, and an additional 7.6 TJ/d of power can be put on the grid (Figure 14, Table 2). When compared to delivering the same output in a SAGD system without Cogen (power provided by the 2014 public grid), the Cogen-based system uses 11.3% less total energy input (58.2 vs. 65.6. TJ/d), has 32% lower conversion losses (16 vs. 23.1 TJ/d) and produces 26% lower GHG emissions (2,950 vs. 4,150 t CO_2/d). This case does not include the efficiency and GHG benefits of obviating the use of single cycle gas turbines to back up renewables.

Therefore, all three Cogen cases show significant improvement in energy efficiency and GHG emissions compared to the Base Case of no Cogen and getting electricity from a coal-dominated electrical grid.

5. Economic Analysis

5.1. Approach and Assumptions Used

Economic analysis was performed using a 20-year Net Present Value (NPV) at 10% discount rate for each of the three case studies associated with deploying Cogeneration on a 33,000 BPD SAGD facility having SOR values of 2, 3 or 4. The cost estimate does not consider the economic value of the oil sands crude that is produced, but only the incremental costs and/or benefits of each Cogeneration case when compared with the Base Case (no cogen) associated with fuel use and price, electricity price, carbon price and capital cost.

To carry out these analyses, a number of assumptions were needed regarding the cost of key components that would ultimately impact the economic viability associated with including Cogeneration in a new SAGD installation or retrofitting Cogen into an existing SAGD facility.

The values chosen for the variables are not meant to be forecasts or recommendations but indicative of the possible range of values that may impact the economic viability of the technology. Table 3 provides a summary of the range of values used, and details on these assumptions are provided here:

Natural gas price. A natural gas price range of \$1.5/gigajoule (GJ) to \$7/GJ was selected based on historical data. In the last 10 years the monthly average natural gas price has ranged from \$0.94/GJ in May 2016 to \$7/GJ in August 2008[7]. The range of natural gas price assumption in this study is conservative as the highest in the last five years was \$5.20/GJ, seen in February 2014.

Carbon Price. A carbon price range of \$30/t CO_2e to \$70/t CO_2e was assumed in this study. When multiplied by the GHG emission reduction (relative to the Base Case) for each Cogeneration case a reduction in the operating costs of the SAGD facility was calculated. The carbon price was applied to the total GHG emission reductions even if they exceeded Alberta's Specified Gas Emitters Regulation of 20% reduction with respect to a facility's baseline, because any additional reductions were considered as credits that could be used elsewhere within the company to offset emissions (or sold to other large final emitters).

Electricity Pool Price. The electricity pool price ranged from \$40/MWh to \$100/MWh based on historical data. The yearly average pool price over the last 10 years has ranged from \$16.56/MWh in 2016 to \$90.01/MWh in 2008.[8] A value of \$40/MWh was used as the low end of our range because the price of electricity is expected to increase as coal retirements start to happen. Moreover, 2015 and 2016 are the only years with an average pool price below \$40/MWh, a reflection of the fact that the Alberta grid is now oversupplied with capacity. A value of \$100/MWh was used at the maximum end of the range because there have been average prices close to this in the past. As coal retirements occur, and there is an increase in renewables on the Alberta grid, it is expected that the price of electricity will rise. In the Cogeneration cases, the power provided to the public grid was assumed to receive 95% of the pool price.

Transmission Price. The price range for delivering electricity to SAGD facilities in the Base Case was set at \$30, \$40 or \$50/MWh based on the Alberta Electric System Operator June 2014 predictions of an expected transmission rate of \$35.27/MWh in 2016 and an expected transmission rate of \$45.98/MWh in 2030[9]. The Base Case importing power from the grid would incur a total cost of transmission cost and the pool prices. Electricity exporters

7 http://www.energy.gov.ab.ca/NaturalGas/1322.asp

8 From AESO historical data. http://ets.aeso.ca

9 AESO, 2014 Transmission Rate Impact Projection Workbook, June 2014

Table 3. Variables in the Economic Analysis for Cogeneration Installations on a 33,000 BPD SAGD facility.

Parameter	Units	Range of Values used
Steam: Oil Ratio	Bbl water/bbl oil	2, 3, 4
Natural Gas Price	$/GJ	$1.5, $3, $5, $7
Carbon Price	$/tonne CO_2	$30, $50, $70
Pool Price	$/MWh	$40, $70, $100*
Transmission Cost	$/MWh	$30, $40, $50
CAPEX	$M/85 MW GT-HRSG	$150, $200, $250
NPV Calculations	-	20 year NPV assuming 10%/yr ROI

* For Case 3 (2 GT running at 60% load factor), the model assumed that for 10% of the year, the cogen units were operating at 100% LF in order to back up wind and solar generation. Power during these times were 4X pool price.

do not need to pay the transmission costs, so this is a cost benefit to cogeneration that exports power.

CAPEX Cost. Three prices – $150 million, $200M and $250M – were chosen to reflect the range of capital costs for installing a single 85 MWe GT and associated heat recovery steam generators with duct burning on either a new 33,000 BPD SAGD facility (lower end of price range) or as a retrofit on an existing SAGD facility (medium to higher end of the price range). In the case of a retrofit, it would be more cost-effective at sites that have sufficient room to add new equipment and more expensive on sites that are congested. For a two-Cogen installation, the CAPEX values were doubled, without taking into consideration potential savings from multiple units. The CAPEX would be spent over three years with 25%, 50% and 25% spent in the first, second and third year, respectively. Operations are assumed to commence in the fourth year. Operating costs were set at 3% of the CAPEX starting in the first year of operation, and sustaining capital was set at 2% of the CAPEX starting in the sixth year of operation.

Incremental Net Present Value over Base Case Calculation. Given the above assumptions and parameters, a 20-year net present value (NPV) at 10% discount rate was calculated for all combinations of each variable. The inflation rate was set at 2% per year for all variables except the carbon price, which is assumed to be a fixed value. Any taxes or royalties were not considered as part of this analysis, as they are project and company specific. When calculating NPV the Base Case power consumption multiplied by the pool price is used as revenue, as there is no longer a requirement to import power. For the two Cogens running at 60% capacity factor, it is assumed that the remaining 40% of the capacity is operated 10% of the time, exporting electricity at four times the pool price in order to back up the power generation from renewables.

5.2. Net Present Values for Cogeneration Case Studies

The Net Present Value (NPV) over the Base Case for the various combinations of the parameters summarized in Table 3 are provided as "heat" maps in Tables 4 to 12 for the three Cogeneration Case Studies over a range of SOR values. The colours green, yellow or red are used to indicate, respectively, favourable, neutral and unfavourable project NPV. The deeper the green colour and greater its extent in a map show that the NPV of the case as being more favourable vis-à-vis the other cases where yellow or red dominates.

Case Study Comparison

The case study involving a SAGD facility with two Cogens operating at 100% load factor (LF) (Table 7 to 9) has the largest variance in NPV values (from -$559M to +$844M for a SOR of 3, Table 8). This is because with two Cogens, the Capex is much higher, much more natural gas is being consumed, but there is more electricity being exported. Consequently, if the electricity price is high and the natural gas price is low, there are greater economic benefits to retrofit with two Cogen units. Alternatively, if the natural gas price is high and the electricity price is low, the two Cogen units would be operating at a larger loss.

The case study with two Cogens operating at 60% LF (Tables 10 to 12) is not as profitable (-$493M to +$586M for a SOR of 3, Table 11) as the 100% LF case because it has lower benefits when the prices of electricity are high. On the other hand, the potential losses are smaller because less gas is consumed, and high gas use is a risk when the gas prices are high and the electricity prices are low.

Incorporating only one Cogen unit into a SAGD facility (Tables 4, 5 and 6) give the lowest downside risk and upside benefit (-$263M to $448M) since its capacity to provide power to the public grid is less than the other two cases.

SOR Impacts

The Case study involving a SAGD facility with two Cogens running at 100% LF can be used to explore the impact of SOR on the economic viability of cogeneration (Table 7 to 9).

Compared to such a facility having a SOR of 3 (Table 8), an SOR of 2 resulted in poorer economic performance for any given set of variables (Table 7) with NPV values about $60M lower for all combination of parameters with a SOR of 2 rather than a SOR of 3.

On the other hand, compared to a SOR of 3 (Table 8), a SOR of 4 increased NPV values by $23M to $32M for all combination of parameters (Table 9). These results suggest that the higher the SOR of a SAGD facility, the greater the benefit of incorporating cogeneration. This is due to the fact that there is more electricity used with a higher SOR, which would be supplied by cogen versus the much more expensive grid power. This also increases the savings in the transmission cost. More heat is required as the SOR increases, so there will be a greater benefit for using the more efficient cogen system instead of an OTSG at higher SORs.

SOR 2 Cogen 1 LF 1

Natural Gas ($/GJ)			$1.5			$3			$5			$7		
			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne		
Power $/MWh		Trans ($/MWh)	$70	$50	$30	$70	$50	$30	$70	$50	$30	$70	$50	$30
$100	Low Capex	$50	429	413	398	376	360	345	305	290	275	234	219	204
		$40	422	407	392	369	354	339	299	284	268	228	213	198
		$30	416	401	386	363	348	333	292	277	262	222	207	191
	Mid Capex	$50	369	354	339	316	301	286	245	230	215	175	160	144
		$40	363	347	332	310	295	279	239	224	209	169	153	138
		$30	356	341	326	303	288	273	233	218	202	162	147	132
	High Capex	$50	309	294	279	256	241	226	186	171	155	115	100	85
		$40	303	288	273	250	235	220	179	164	149	109	94	78
		$30	297	282	266	244	229	213	173	158	143	103	87	72
$70	Low Capex	$50	256	241	225	203	188	172	132	117	102	62	47	31
		$40	250	234	219	197	181	166	126	111	96	55	40	25
		$30	243	228	213	190	175	160	120	105	89	49	34	19
	Mid Capex	$50	196	181	166	143	128	113	73	57	42	2	-13	-28
		$40	190	175	159	137	122	107	66	51	36	-4	-19	-35
		$30	184	168	153	131	115	100	60	45	30	-11	-26	-41
	High Capex	$50	137	121	106	84	68	53	13	-2	-17	-58	-73	-88
		$40	130	115	100	77	62	47	7	-9	-24	-64	-79	-94
		$30	124	109	94	71	56	41	0	-15	-30	-70	-85	-101
$40	Low Capex	$50	83	68	53	30	15	0	-40	-56	-71	-111	-126	-141
		$40	77	62	46	24	9	-7	-47	-62	-77	-117	-133	-148
		$30	71	55	40	18	2	-13	-53	-68	-83	-124	-139	-154
	Mid Capex	$50	23	8	-7	-29	-45	-60	-100	-115	-131	-171	-186	-201
		$40	17	2	-13	-36	-51	-66	-106	-122	-137	-177	-192	-207
		$30	11	-4	-20	-42	-57	-72	-113	-128	-143	-183	-198	-214
	High Capex	$50	-36	-51	-67	-89	-104	-120	-160	-175	-190	-230	-246	-261
		$40	-42	-58	-73	-95	-111	-126	-166	-181	-196	-237	-252	-267
		$30	-49	-64	-79	-102	-117	-132	-172	-188	-203	-243	-258	-273

Table 4. Net Present Value Heat Map for a SAGD Facility with a SOR of 2 and One 85MWe Cogen Operating at 100% Load Factor.

SOR 3 Cogen 1 LF 1

Natural Gas ($/GJ)			$1.5 Carbon $/tonne			$3 Carbon $/tonne			$5 Carbon $/tonne			$7 Carbon $/tonne		
Power $/MWh		Trans ($/MWh)	$70	$50	$30	$70	$50	$30	$70	$50	$30	$70	$50	$30
$100	Low Capex	$50	448	430	413	395	377	360	324	307	290	254	236	219
		$40	439	422	404	386	369	351	316	298	281	245	228	210
		$30	430	413	396	377	360	343	307	290	272	236	219	202
	Mid Capex	$50	388	371	353	335	318	300	265	247	230	194	177	159
		$40	379	362	345	326	309	292	256	239	221	185	168	151
		$30	371	353	336	318	301	283	247	230	213	177	159	142
	High Capex	$50	328	311	294	275	258	241	205	188	170	134	117	100
		$40	320	302	285	267	249	232	196	179	162	126	108	91
		$30	311	294	276	258	241	224	188	170	153	117	100	82
$70	Low Capex	$50	275	258	240	222	205	187	151	134	117	81	63	46
		$40	266	249	232	213	196	179	143	125	108	72	55	38
		$30	258	240	223	205	187	170	134	117	99	64	46	29
	Mid Capex	$50	215	198	181	162	145	128	92	74	57	21	4	-13
		$40	207	189	172	154	136	119	83	66	48	13	-5	-22
		$30	198	181	163	145	128	110	74	57	40	4	-13	-31
	High Capex	$50	156	138	121	103	85	68	32	15	-3	-38	-56	-73
		$40	147	130	112	94	77	59	23	6	-11	-47	-64	-82
		$30	138	121	104	85	68	51	15	-2	-20	-56	-73	-90
$40	Low Capex	$50	102	85	68	49	32	15	-21	-39	-56	-92	-109	-127
		$40	94	76	59	41	23	6	-30	-47	-65	-101	-118	-135
		$30	85	68	50	32	15	-3	-39	-56	-73	-109	-127	-144
	Mid Capex	$50	43	25	8	-10	-28	-45	-81	-98	-116	-152	-169	-186
		$40	34	17	-1	-19	-36	-54	-90	-107	-124	-160	-178	-195
		$30	25	8	-9	-28	-45	-62	-98	-116	-133	-169	-186	-204
	High Capex	$50	-17	-34	-52	-70	-87	-105	-141	-158	-175	-211	-229	-246
		$40	-26	-43	-60	-79	-96	-113	-149	-167	-184	-220	-237	-255
		$30	-34	-52	-69	-87	-105	-122	-158	-175	-193	-229	-246	-263

Table 5. Net Present Value Heat Map for a SAGD Facility with a SOR of 3 and One 85MWe Cogen Operating at 100% Load Factor.

SOR 4 Cogen 1 LF 1

Natural Gas ($/GJ)			$1.5			$3			$5			$7		
			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne		
Power $/MWh		Trans ($/MWh)	$70	$50	$30	$70	$50	$30	$70	$50	$30	$70	$50	$30
$100	Low Capex	$50	467	448	428	414	395	375	343	324	305	273	253	234
		$40	456	437	417	403	384	364	332	313	294	262	242	223
		$30	445	426	406	392	373	353	321	302	283	251	231	212
	Mid Capex	$50	407	388	368	354	335	316	284	264	245	213	194	174
		$40	396	377	357	343	324	305	273	253	234	202	183	163
		$30	385	366	346	332	313	293	262	242	223	191	172	152
	High Capex	$50	348	328	309	295	275	256	224	205	185	154	134	115
		$40	337	317	298	284	264	245	213	194	174	143	123	104
		$30	326	306	287	273	253	234	202	183	163	132	112	93
$70	Low Capex	$50	294	275	255	241	222	202	171	151	132	100	81	61
		$40	283	264	244	230	211	191	160	140	121	89	70	50
		$30	272	253	233	219	200	180	149	129	110	78	59	39
	Mid Capex	$50	235	215	196	182	162	143	111	92	72	40	21	2
		$40	224	204	185	171	151	132	100	81	61	29	10	-9
		$30	213	193	174	160	140	121	89	70	50	18	-1	-20
	High Capex	$50	175	156	136	122	103	83	51	32	13	-19	-39	-58
		$40	164	145	125	111	92	72	40	21	2	-30	-50	-69
		$30	153	133	114	100	81	61	29	10	-10	-41	-61	-80
$40	Low Capex	$50	122	102	83	69	49	30	-2	-21	-41	-73	-92	-112
		$40	111	91	72	58	38	19	-13	-32	-52	-84	-103	-123
		$30	100	80	61	47	27	8	-24	-43	-63	-95	-114	-134
	Mid Capex	$50	62	42	23	9	-11	-30	-62	-81	-101	-132	-152	-171
		$40	51	31	12	-2	-22	-41	-73	-92	-112	-143	-163	-182
		$30	40	20	1	-13	-33	-52	-84	-103	-123	-154	-174	-193
	High Capex	$50	2	-17	-37	-51	-70	-90	-121	-141	-160	-192	-211	-231
		$40	-9	-28	-48	-62	-81	-101	-132	-152	-171	-203	-222	-242
		$30	-20	-39	-59	-73	-92	-112	-143	-163	-182	-214	-233	-253

Table 6. Net Present Value Heat Map for a SAGD Facility with a SOR of 4 and One 85MWe Cogen Operating at 100% Load Factor.

SOR 2 Cogen 2 LF 1

Natural Gas ($/GJ)			$1.5			$3			$5			$7		
			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne		
Power $/MWh		Trans ($/MWh)	$70	$50	$30	$70	$50	$30	$70	$50	$30	$70	$50	$30
$100	Low Capex	$50	785	765	746	669	650	630	516	496	477	362	342	323
		$40	776	756	737	661	641	622	507	487	468	353	334	314
		$30	767	748	728	652	632	613	498	479	459	344	325	305
	Mid Capex	$50	665	646	626	550	531	511	396	377	357	243	223	204
		$40	657	637	617	541	522	502	388	368	348	234	214	195
		$30	648	628	609	533	513	493	379	359	340	225	206	186
	High Capex	$50	546	527	507	431	411	392	277	258	238	123	104	84
		$40	537	518	498	422	402	383	268	249	229	115	95	75
		$30	529	509	489	413	394	374	260	240	220	106	86	67
$70	Low Capex	$50	441	421	402	326	306	287	172	152	133	18	-1	-21
		$40	432	413	393	317	297	278	163	144	124	10	-10	-30
		$30	424	404	384	308	289	269	155	135	115	1	-19	-38
	Mid Capex	$50	322	302	283	206	187	167	53	33	14	-101	-121	-140
		$40	313	293	274	198	178	159	44	24	5	-110	-129	-149
		$30	304	285	265	189	169	150	35	16	-4	-119	-138	-158
	High Capex	$50	202	183	163	87	68	48	-67	-86	-106	-220	-240	-259
		$40	194	174	154	78	59	39	-75	-95	-115	-229	-249	-268
		$30	185	165	146	70	50	30	-84	-104	-123	-238	-257	-277
$40	Low Capex	$50	97	78	58	-18	-38	-57	-172	-191	-211	-325	-345	-365
		$40	89	69	49	-27	-46	-66	-180	-200	-220	-334	-354	-373
		$30	80	60	41	-35	-55	-75	-189	-209	-228	-343	-362	-382
	Mid Capex	$50	-22	-42	-61	-137	-157	-176	-291	-311	-330	-445	-464	-484
		$40	-31	-50	-70	-146	-166	-185	-300	-319	-339	-453	-473	-493
		$30	-39	-59	-79	-155	-174	-194	-308	-328	-348	-462	-482	-501
	High Capex	$50	-141	-161	-180	-257	-276	-296	-410	-430	-449	-564	-584	-603
		$40	-150	-170	-189	-265	-285	-304	-419	-439	-458	-573	-592	-612
		$30	-159	-178	-198	-274	-294	-313	-428	-447	-467	-582	-601	-621

Table 7. Net Present Value Heat Map for a SAGD Facility with a SOR of 2 and Two 85MWe Cogen Operating at 100% Load Factor.

SOR 3 Cogen 2 LF 1

Natural Gas ($/GJ)			$1.5			$3			$5			$7		
			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne		
Power $/MWh		Trans ($/MWh)	$70	$50	$30	$70	$50	$30	$70	$50	$30	$70	$50	$30
$100	Low Capex	$50	844	817	791	736	710	683	593	567	540	450	424	397
		$40	831	805	779	724	698	671	581	555	528	438	411	385
		$30	819	793	766	712	685	659	569	542	516	426	399	373
	Mid Capex	$50	724	698	671	617	591	564	474	447	421	331	304	278
		$40	712	686	659	605	578	552	462	435	409	319	292	266
		$30	700	673	647	592	566	540	449	423	397	306	280	253
	High Capex	$50	605	579	552	498	471	445	355	328	302	212	185	159
		$40	593	566	540	485	459	433	342	316	289	199	173	146
		$30	581	554	528	473	447	420	330	304	277	187	161	134
$70	Low Capex	$50	497	471	444	390	363	337	247	220	194	104	77	51
		$40	485	458	432	378	351	325	234	208	182	91	65	38
		$30	473	446	420	365	339	312	222	196	169	79	53	26
	Mid Capex	$50	378	351	325	270	244	218	127	101	75	-16	-42	-69
		$40	366	339	313	258	232	205	115	89	62	-28	-54	-81
		$30	353	327	300	246	220	193	103	76	50	-40	-67	-93
	High Capex	$50	259	232	206	151	125	98	8	-18	-45	-135	-161	-188
		$40	246	220	193	139	112	86	-4	-31	-57	-147	-174	-200
		$30	234	208	181	127	100	74	-16	-43	-69	-160	-186	-212
$40	Low Capex	$50	151	124	98	43	17	-10	-100	-126	-153	-243	-269	-296
		$40	138	112	85	31	5	-22	-112	-139	-165	-255	-282	-308
		$30	126	100	73	19	-8	-34	-124	-151	-177	-267	-294	-320
	Mid Capex	$50	31	5	-22	-76	-102	-129	-219	-246	-272	-362	-389	-415
		$40	19	-7	-34	-88	-115	-141	-231	-258	-284	-374	-401	-427
		$30	7	-20	-46	-101	-127	-153	-244	-270	-297	-387	-413	-440
	High Capex	$50	-88	-114	-141	-195	-222	-248	-338	-365	-391	-482	-508	-534
		$40	-100	-127	-153	-208	-234	-260	-351	-377	-404	-494	-520	-547
		$30	-113	-139	-165	-220	-246	-273	-363	-389	-416	-506	-533	-559

Table 8. Net Present Value Heat Map for a SAGD Facility with a SOR of 3 and Two 85MWe Cogen Operating at 100% Load Factor.

SOR 4 Cogen 2 LF 1

Natural Gas ($/GJ)			$1.5			$3			$5			$7		
			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne		
Power $/MWh		Trans ($/MWh)	$70	$50	$30	$70	$50	$30	$70	$50	$30	$70	$50	$30
$100	Low Capex	$50	876	847	818	770	741	712	629	600	570	488	459	429
		$40	861	831	802	755	725	696	613	584	555	472	443	413
		$30	845	815	786	739	709	680	598	568	539	456	427	398
	Mid Capex	$50	757	728	698	651	622	592	510	480	451	369	339	310
		$40	741	712	682	635	606	576	494	465	435	353	323	294
		$30	725	696	667	619	590	561	478	449	419	337	308	278
	High Capex	$50	638	608	579	532	502	473	391	361	332	249	220	191
		$40	622	592	563	516	487	457	375	345	316	234	204	175
		$30	606	577	547	500	471	441	359	330	300	218	188	159
$70	Low Capex	$50	529	499	470	423	394	364	282	252	223	140	111	82
		$40	513	484	454	407	378	348	266	237	207	125	95	66
		$30	497	468	438	391	362	333	250	221	191	109	79	50
	Mid Capex	$50	410	380	351	304	274	245	162	133	104	21	-8	-38
		$40	394	364	335	288	258	229	147	117	88	5	-24	-53
		$30	378	349	319	272	243	213	131	101	72	-10	-40	-69
	High Capex	$50	290	261	231	184	155	125	43	14	-16	-98	-128	-157
		$40	274	245	216	168	139	110	27	-2	-32	-114	-143	-173
		$30	259	229	200	153	123	94	11	-18	-47	-130	-159	-189
$40	Low Capex	$50	181	152	123	75	46	17	-66	-95	-125	-207	-236	-266
		$40	166	136	107	60	30	1	-82	-111	-140	-223	-252	-282
		$30	150	120	91	44	14	-15	-97	-127	-156	-239	-268	-297
	Mid Capex	$50	62	33	3	-44	-73	-103	-185	-214	-244	-326	-356	-385
		$40	46	17	-13	-60	-89	-118	-201	-230	-260	-342	-371	-401
		$30	30	1	-28	-75	-105	-134	-217	-246	-275	-358	-387	-417
	High Capex	$50	-57	-87	-116	-163	-193	-222	-304	-334	-363	-446	-475	-504
		$40	-73	-102	-132	-179	-208	-238	-320	-350	-379	-461	-491	-520
		$30	-89	-118	-148	-195	-224	-254	-336	-365	-395	-477	-507	-536

Table 9. Net Present Value Heat Map for a SAGD Facility with a SOR of 4 and Two 85MWe Cogen Operating at 100% Load Factor.

SOR 2 Cogen 2 LF 0.6

Natural Gas ($/GJ)			$1.5			$3			$5			$7		
			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne		
Power $/MWh		Trans ($/MWh)	$70	$50	$30	$70	$50	$30	$70	$50	$30	$70	$50	$30
$100	Low Capex	$50	547	533	520	476	463	449	381	368	355	287	274	260
		$40	538	525	511	467	454	440	373	359	346	278	265	251
		$30	529	516	502	458	445	432	364	351	337	269	256	243
	Mid Capex	$50	427	414	401	357	343	330	262	249	235	168	154	141
		$40	419	405	392	348	334	321	253	240	227	159	146	132
		$30	410	397	383	339	326	312	245	231	218	150	137	123
	High Capex	$50	308	295	281	237	224	211	143	129	116	48	35	22
		$40	299	286	273	228	215	202	134	121	107	40	26	13
		$30	291	277	264	220	206	193	125	112	99	31	17	4
$70	Low Capex	$50	281	268	255	210	197	184	116	103	89	21	8	-5
		$40	272	259	246	202	188	175	107	94	80	13	-1	-14
		$30	264	250	237	193	180	166	98	85	72	4	-9	-23
	Mid Capex	$50	162	149	135	91	78	64	-3	-17	-30	-98	-111	-125
		$40	153	140	126	82	69	56	-12	-25	-39	-107	-120	-133
		$30	144	131	118	74	60	47	-21	-34	-48	-115	-129	-142
	High Capex	$50	43	29	16	-28	-42	-55	-123	-136	-149	-217	-231	-244
		$40	34	20	7	-37	-50	-64	-131	-145	-158	-226	-239	-253
		$30	25	12	-2	-46	-59	-72	-140	-154	-167	-235	-248	-261
$40	Low Capex	$50	16	2	-11	-55	-68	-82	-150	-163	-176	-244	-257	-271
		$40	7	-6	-20	-64	-77	-91	-158	-172	-185	-253	-266	-279
		$30	-2	-15	-28	-73	-86	-99	-167	-180	-194	-261	-275	-288
	Mid Capex	$50	-104	-117	-130	-174	-188	-201	-269	-282	-296	-363	-377	-390
		$40	-112	-126	-139	-183	-197	-210	-278	-291	-304	-372	-385	-399
		$30	-121	-134	-148	-192	-205	-219	-286	-300	-313	-381	-394	-408
	High Capex	$50	-223	-236	-250	-294	-307	-320	-388	-402	-415	-483	-496	-509
		$40	-232	-245	-258	-302	-316	-329	-397	-410	-424	-491	-505	-518
		$30	-240	-254	-267	-311	-325	-338	-406	-419	-432	-500	-513	-527

Table 10. Net Present Value Heat Map for a SAGD Facility with a SOR of 2 and Two 85MWe Cogen Operating at 60% Load Factor.

SOR 3 Cogen 2 LF 0.6

Natural Gas ($/GJ)			$1.5			$3			$5			$7		
			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne		
Power $/MWh		Trans ($/MWh)	$70	$50	$30	$70	$50	$30	$70	$50	$30	$70	$50	$30
$100	Low Capex	$50	586	569	552	519	501	484	429	411	394	338	321	304
		$40	574	557	539	506	489	472	416	399	382	326	309	291
		$30	562	544	527	494	477	459	404	387	369	314	296	279
	Mid Capex	$50	467	450	432	399	382	365	309	292	274	219	202	184
		$40	455	437	420	387	370	352	297	280	262	207	189	172
		$30	443	425	408	375	358	340	285	267	250	195	177	160
	High Capex	$50	348	330	313	280	263	245	190	173	155	100	82	65
		$40	335	318	301	268	250	233	178	160	143	87	70	53
		$30	323	306	288	256	238	221	165	148	131	75	58	40
$70	Low Capex	$50	319	302	285	252	234	217	162	144	127	71	54	37
		$40	307	290	272	240	222	205	149	132	115	59	42	24
		$30	295	278	260	227	210	192	137	120	102	47	30	12
	Mid Capex	$50	200	183	165	132	115	98	42	25	8	-48	-65	-83
		$40	188	170	153	120	103	85	30	13	-5	-60	-78	-95
		$30	176	158	141	108	91	73	18	0	-17	-72	-90	-107
	High Capex	$50	81	63	46	13	-4	-22	-77	-94	-112	-167	-185	-202
		$40	69	51	34	1	-16	-34	-89	-107	-124	-179	-197	-214
		$30	56	39	22	-11	-29	-46	-102	-119	-136	-192	-209	-226
$40	Low Capex	$50	53	35	18	-15	-33	-50	-105	-123	-140	-195	-213	-230
		$40	40	23	5	-27	-45	-62	-118	-135	-152	-208	-225	-243
		$30	28	11	-7	-40	-57	-74	-130	-147	-165	-220	-237	-255
	Mid Capex	$50	-67	-84	-102	-134	-152	-169	-225	-242	-259	-315	-332	-350
		$40	-79	-96	-114	-147	-164	-181	-237	-254	-272	-327	-344	-362
		$30	-91	-109	-126	-159	-176	-194	-249	-267	-284	-339	-357	-374
	High Capex	$50	-186	-204	-221	-254	-271	-289	-344	-361	-379	-434	-452	-469
		$40	-198	-216	-233	-266	-283	-301	-356	-374	-391	-446	-464	-481
		$30	-211	-228	-245	-278	-296	-313	-368	-386	-403	-459	-476	-493

Table 11. Net Present Value Heat Map for a SAGD Facility with a SOR of 3 and Two 85MWe Cogen Operating at 60% Load Factor.

SOR 4 Cogen 2 LF 0.6

Natural Gas ($/GJ)			$1.5			$3			$5			$7		
			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne			Carbon $/tonne		
Power $/MWh		Trans ($/MWh)	$70	$50	$30	$70	$50	$30	$70	$50	$30	$70	$50	$30
$100	Low Capex	$50	613	594	574	546	526	507	455	436	416	365	346	326
		$40	597	578	558	530	510	491	440	420	401	349	330	310
		$30	582	562	543	514	495	475	424	404	385	334	314	295
	Mid Capex	$50	494	474	455	426	407	387	336	317	297	246	226	207
		$40	478	459	439	411	391	371	320	301	281	230	211	191
		$30	462	443	423	395	375	356	305	285	266	214	195	175
	High Capex	$50	375	355	336	307	288	268	217	197	178	127	107	88
		$40	359	339	320	291	272	252	201	182	162	111	91	72
		$30	343	324	304	275	256	236	185	166	146	95	76	56
$70	Low Capex	$50	346	326	307	278	259	239	188	168	149	98	78	59
		$40	330	311	291	262	243	223	172	153	133	82	62	43
		$30	314	295	275	247	227	208	156	137	117	66	47	27
	Mid Capex	$50	227	207	187	159	139	120	69	49	30	-21	-41	-61
		$40	211	191	172	143	124	104	53	33	14	-37	-57	-76
		$30	195	175	156	127	108	88	37	18	-2	-53	-73	-92
	High Capex	$50	107	88	68	40	20	1	-51	-70	-90	-141	-160	-180
		$40	91	72	52	24	4	-15	-66	-86	-105	-157	-176	-196
		$30	76	56	37	8	-12	-31	-82	-102	-121	-172	-192	-211
$40	Low Capex	$50	78	59	39	11	-9	-28	-79	-99	-118	-170	-189	-209
		$40	63	43	24	-5	-25	-44	-95	-115	-134	-185	-205	-224
		$30	47	27	8	-21	-40	-60	-111	-131	-150	-201	-221	-240
	Mid Capex	$50	-41	-60	-80	-109	-128	-148	-199	-218	-238	-289	-308	-328
		$40	-57	-76	-96	-124	-144	-163	-215	-234	-254	-305	-324	-344
		$30	-73	-92	-112	-140	-160	-179	-230	-250	-269	-321	-340	-360
	High Capex	$50	-160	-180	-199	-228	-247	-267	-318	-338	-357	-408	-428	-447
		$40	-176	-196	-215	-244	-263	-283	-334	-353	-373	-424	-444	-463
		$30	-192	-211	-231	-260	-279	-299	-350	-369	-389	-440	-459	-479

Table 12. Net Present Value Heat Map for a SAGD Facility with a SOR of 4 and Two 85MWe Cogen Operating at 60% Load Factor.

5.3. Sensitivity Analyses

Sensitivity analyses were carried out for each of the variables by fixing all other variables at their respective midpoint of the range and then calculating the NPV using the extremes of the range for the variables in question. This analysis was done for all three of the SAGD Case studies at SOR values of 2, 3, and 4. The results, presented in Figure 13, provided the following insights:

- At the midpoint values for all parameters (vertical dashed lines, Figure 13), all NPV values were assessed to be positive.
- The electrical pool price and natural gas price have the largest impact on the economics of the project. The Capex also has a significant impact on the project economics, while the impact of the transmission cost and CO_2 price on NPV are smaller.
- The SAGD facilities with the two 85 MWe Cogens tended to show a more positive NPV than those facilities with only one Cogen.
- As the SOR increases the NPV values were more positive.

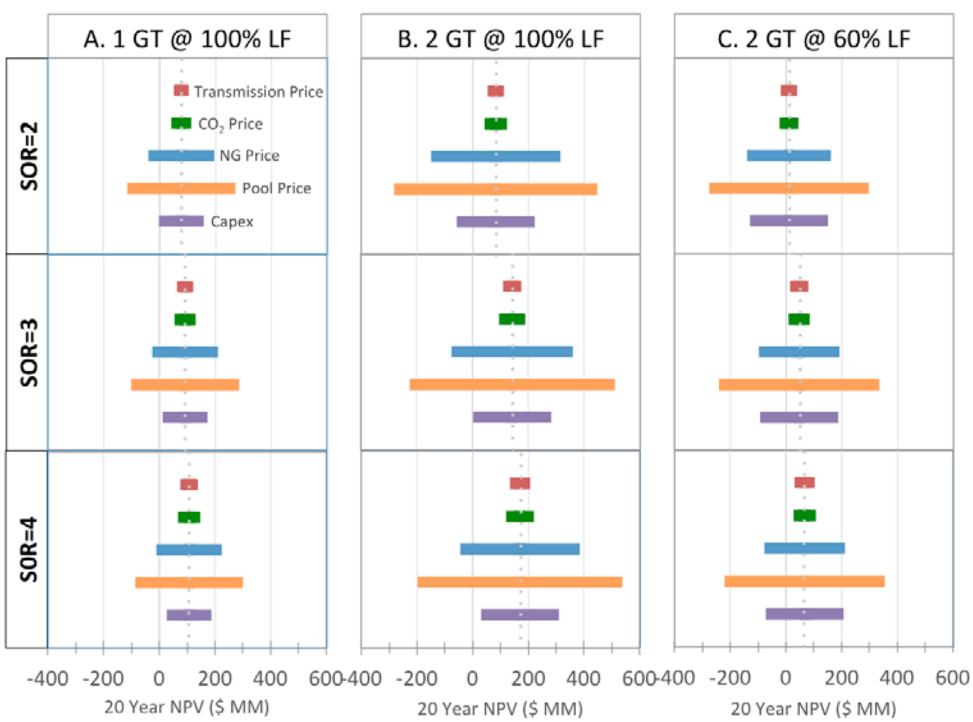


Figure 15. Sensitivity analyses for cogeneration cases involving one (A) or two (B,C) 85 MWe Cogen units running at 100% LF (A,B) or 60% LF (C) installed on SAGD facilities having a SOR of 2 to 4. The dotted vertical line shows the NPV when all assessments are at the mid-point.

6. Discussion

6.1. The Costs, Benefits and Risks of Large-Scale Cogen on SAGD sites

There are minimal technical and operational risks of deploying co-generation in oil sands. Gas turbines and heat recovery steam generators (HRSG) are mature, commercial technologies with many large installations already deployed in oil sands operations in general or in SAGD facilities more specifically.

Scaling cogen with highly efficient duct burning to meet the steam requirements for SAGD would mean deploying two 85 MWe gas turbines plus HRSGs on each 33,000 BPD SAGD site (at SOR=3). Given Behind-The-Fence power demand for SAGD, this Cogen installation at a single facility could deliver low carbon thermal power to meet about 2% of the electricity demands for the public grid of Alberta. With a theoretical potential for over 30 such SAGD facilities in the province, SAGD Cogeneration could become a major source of reliable power for the Alberta grid.

The potential benefits of this strategy should include:

- Improving the systems level efficiency of conventional technologies (NGSC, NGCC, OTSG) that are used to generate heat or power from natural gas fuels;
- Since less fuel is combusted in the production of this heat and power, the system level GHG emissions should be lower with cogeneration than with a system using similar fuels but not using cogeneration;
- Providing a reliable, low cost source of base load power to the Alberta grid;
- Potentially providing back up for renewable power into the grid, assuming it does not adversely affect oil sands crude production;
- Potential to reduce the GHG footprint of oil sands crude production and/or the GHG intensity of the Alberta grid;
- Generates a new product from oil sands operations that could assist in the competitiveness of SAGD facilities, especially in times of low oil prices; and
- Positions oil sands companies as part of the solution to the challenge of climate change and GHG emissions reductions.

To further explore the system level costs, benefits and trade-offs of cogeneration, this work needs to be extended to include all SAGD facilities and all power generation in the province. This is the focus of the next report in this series.

6.2. GHG Avoidance Costs of Cogeneration with Regard to Carbon Capture and Storage

The current commercial process for post-combustion carbon capture (PCC) uses an amine solvent to remove CO_2 from the combustion exhaust. The 2013 ECM Study[10] is the latest published study for PCC of a 33,000 BPD and SOR of 3 SAGD project. The PCC capital investment and operating costs were extracted from that study, while the assumptions of Alberta grid GHG Intensity, commodity prices, carbon compliance costs and cost of capital in this study's economics were applied in order to estimate the CO_2 avoidance costs.

The estimated CO_2 avoidance of PCC was respectively $90 per undiscounted tonne and $130 per discounted tonne of CO_2 avoided on pre-tax and pre-oil sands royalty basis. For comparison and also on a pre-tax and pre-oil sand royalty basis, oil sands crude produced by cogeneration would incur an avoided cost of $70 per undiscounted tonne and $100 per discounted tonne of CO_2 avoided using the same assumptions. The discounting of the avoided tonnes by 3% was to account for the benefits of earlier GHG reduction if one technology could initiate greater GHG reduction sooner than the other. It would seem that a single 33,000 BPD SAGD project deploying cogeneration would result in about 30% lower CO_2 avoidance cost. It should be noted this cost advantage depends on the pace at which the Alberta grid GHG intensity reduction is accelerated by adding cogeneration in more SAGD projects. Lower Alberta grid GHG intensity would result in more avoided tonnage for the PCC case while reducing those for the Cogen case. In that scenario, the PCC avoided cost would decrease while that of cogeneration would increase until the two first become equal and then the former avoided cost would become lower than the latter.

10 Alberta Innovates – Energy and Environment Solutions, ECM Evaluation Study Report, November 2013.

6.3. Decision Factors for SAGD Facility Retrofit Projects

As described earlier, most SAGD facilities had installed OTSGs for steam generation and have imported electricity from the Alberta grid. For these projects and depending on their respective SOR, the retrofit alternatives are:

a) Install two 7E gas turbines and a full-size heat recovery steam generator with duct burners and forced air fans, and either put all OTSG on standby or remove all OTSG from the facility;

b) Install one 7E gas turbine that is connected to a HRSG with duct burners and forced air fans, and run OTSG as required to generate sufficient steam for oil sands crude production;

c) Install a number of gas turbines, and modify the OTSG to accept hot exhaust from the gas turbine to operate like a HRSG; or

d) a combination of the above.

Note that only a) and b) were assessed in this study. All these alternatives are technically feasible. It is then an investment decision based on the financial returns of investing in new gas turbines and HRSG, including the capital costs of site modifications to accommodate the new gas turbines and HRSG, and tie-in to the steam and power distribution systems.

The returns will depend on the net revenue from electricity sales and emission reduction credits arising from lowering the GHG intensity of Alberta's electrical grid and oil sands crude production. The electricity price and GHG reduction credits will be a function of Alberta's GHG reduction policy, including the phase out of coal-fired power generation and promotion of more renewable power generation. As seen from the analyses of this study, the pre-dominant factors are Alberta pool price, capital cost of cogeneration retrofit and natural gas price.

7. Recommendations

7.1. Evaluation of Actual SAGD Project Retrofit

The evaluations in this report are based on generic SAGD projects at SOR range of 2 to 4. The next step in the evaluation should include two to four specific operating SAGD projects. Ideally these projects would cover the range of SOR of this study and should represent the diversity of oil sands reservoirs, i.e. geographic locations that will affect the quality of the reservoir. In addition, site-specific equipment layout and infrastructure as well as the project operator's preferred engineering design and construction specifications will permit a better definition of project execution, and hence capital and operating cost estimates.

These parameters will determine retrofitting cogeneration project economics that is essential for investment decisions. Further, by continuing with specific projects, the economics can include royalty and tax conditions that will better inform decisions on whether to invest in cogeneration.

7.2. Evaluation of New SAGD Technology

A number of new SAGD technologies are being evaluated or piloted that are less energy intensive than current technologies. For example, solvent-aided process (SAP) replaces a portion of the steam with liquefied petroleum gas such as propane or butane. The combined effects of steam and solvent would achieve the same viscosity reduction as steam alone. How SAP and other new SAGD technologies would affect energy use and hence cogeneration should be assessed.

7.3. Impact of Cogeneration on Alberta Grid

This study was focused on the techno-economic issues of retrofitting cogeneration into one 33,000 BPD operating SAGD project. The next step should include the evaluation of the impacts on the Alberta grid as a result of retrofitting all existing SAGD projects and installing cogeneration in new SAGD projects over the next 15 years. This evaluation should include assessing how much of the grid and SAGD GHG intensity could be reduced, how accelerated coal power generation phase-out may be supported by implementing cogeneration in SAGD projects, and how renewable power generation may be adequately backed up by SAGD cogeneration power in the prevailing grid system operations.

7.4. Synergy of Cogeneration Load Factor with SAGD

In this study for a single SAGD project, it was postulated that gas turbines could be ramped up to 100% output from 60% during normal SAGD operation to provide backup power to the grid when renewables are offline. While the gas turbine operates between 60% and 100% load factor, it is assumed that the steam output is maintained constant. The latter is achieved through modulating the HRSG operation, for example, turning down duct burning or forced air-duct burning while the gas turbine is ramped up to 100%.

It is worthwhile to delve deeper into SAGD operational issues that would impact oil production while the HRSG duct burning or forced air-duct burning is modulated. Also, the grid system issues of other power generators working in concert with SAGD projects, and how climate conditions affect renewable power generation in supplying power to the grid to meet Alberta's power demand on a daily to annual basis, should be studied. Also, the emission of criteria air contaminants such as NO_x should be evaluated as the gas turbine is ramped up or down in tandem with duct burning or forced air-duct burning modulation.

7.5. Analysis of Other Types of Gas Turbines

For various sizes of oil sands operations, there may be other choices possible for the gas turbine and HRSG combinations for both retrofit and new facilities. Gas turbine units in the 30 to 50 MWe size range may be considered, including the use of aero-derivative gas turbine units which are more efficient for power (but with lower exhaust temperatures, require additional fuel for duct burning). These are also more responsive to flexible operation and quicker ramp rates for load following with local renewables.

7.6. Alternative Cogeneration Technologies

Natural gas-fired cogeneration using gas turbines and HRSG in SAGD projects are proven commercial technologies to produce electricity and high pressure steam. Cogen would lower gas turbines' and HRSG's respective GHG emission intensities in oil sands projects and the technologies are ready for implementation today.

However, there are other technologies in development that are much less advanced. In the 2013 ECM Study published by Alberta Innovates, solid oxide fuel cells (SOFC) were evaluated as an alternative cogeneration technology and shown to be a viable technology for SAGD application. Their electricity generation efficiency is about 55% to 60% which is higher than that of single cycle gas turbines. From this perspective, SOFCs are worthy of further development and assessment. Today, they are deemed pre-commercial at a technology readiness level of 7, which means they require large-scale demonstration at the multiple megawatts scale. With further technology development and demonstration, the total installed capital cost of commercial SOFC may be lowered to the range of cogeneration by around 2030.

To that end, another study should be undertaken to identify and evaluate alternative cogeneration technologies in addition to SOFC in terms of their techno-economic capabilities and GHG reduction and avoidance cost, as well as their development path and costs from their current technology readiness level to commercialization.

APPENDIX

Appendix 1. Environmental Considerations for Industrial Gas Turbine Systems

The Alberta energy sectors in oil/gas and in electricity have a major opportunity to reduce GHGs and air pollutants. Stationary gas turbine energy systems fueled by natural gas can provide efficient solutions through integrated cogeneration, district energy and waste heat recovery, thereby complementing other renewable forms of heat and electricity supply

Over the last two decades, gas turbines have been among the most rapidly growing energy generation technologies. Both industrial 'Frame' units, and units derived from aircraft engines, have been used for pipeline compressors, in the electricity sector to drive electrical generators, and to provide both heat and power for industrial or municipal applications.

Over half of the gas turbine fleet in Canada has been added since 2000 (Fig A1), resulting in 17,000 MW newly installed systems in more than 100 locations[11]. They have been instrumental in avoiding about 40 Mt CO_2/y of GHG and 300 kt/y of air pollution emissions across Canada[12]. About 3,000 MWe are located in the Alberta oil sands sector and there is the potential to add much more.

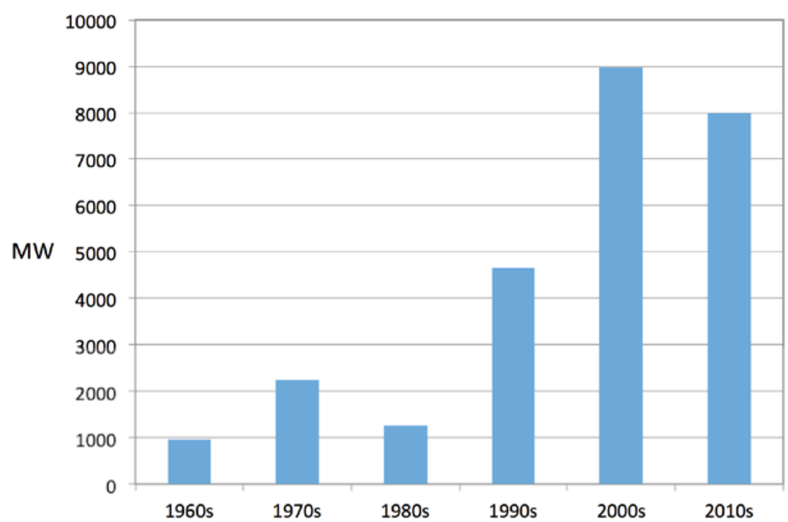


Figure A1. Timeline of installation of gas turbine systems in Canada; total of 26,000 MW installed

Gas turbines are thermodynamic engines that use a steady inflow of a gas (mostly air), compressed and fired with gaseous or liquid fuel (Fig A2). As seen in Figure A2, this high pressure hot gas mixture is expanded through a turbine to generate output power that can be

11 Klein, M. Gas Turbine Systems as a Cleaner Energy Choice. Paper for Combustion Institute of Canada, Ottawa, May 2010.

12 Klein, M. Gas Turbine Emissions. Ed. By Lieuwen & Yang, Chapter 2 & 4, Cambridge Press, 2013.

used for thrust in an aircraft engine, propulsion in a marine vessel, or as industrial shaft power for applications such as pipeline compression and electrical power.

A unique feature of these units is that the considerable heat still available in the exhaust stream can be provided to a Waste Heat Recovery (WHR) system to drive steam turbines, and/or to produce thermal energy for industries for efficient integrated energy production.

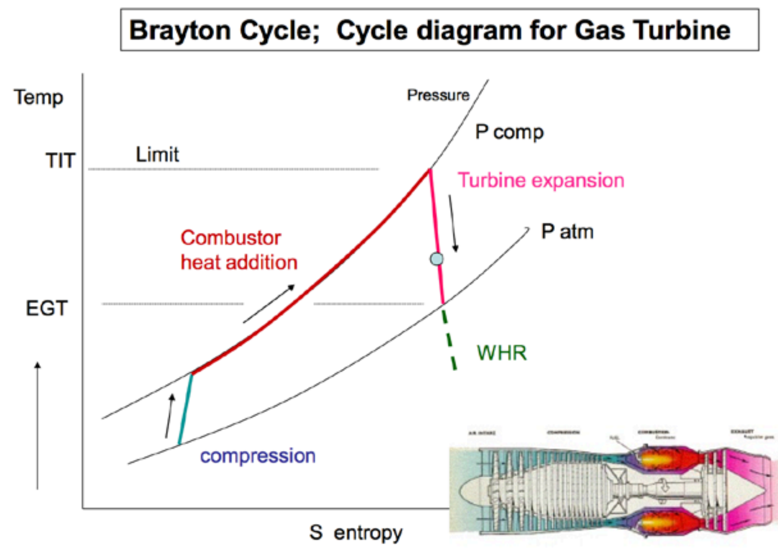


Figure A2. The air and energy cycle of a gas turbine.

Gas turbine energy and environmental performance is heavily influenced by ambient air conditions, because this air provides the working fluid that turns the turbine blades. Energy from hot gases is proportional to mass flow, heat capacity and temperature rise above ambient.

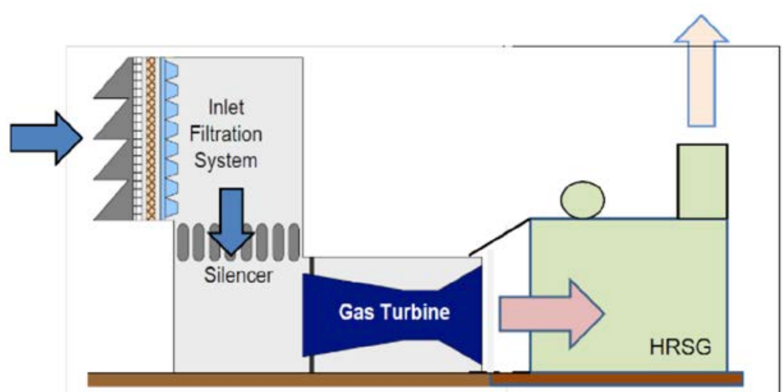


Figure A3. Airflow in a gas turbine power plant.

Why is a 'gas turbine' called that? **Not because it burns natural gas fuel.** The 'gas' is high pressure hot air going through the turbine blades, and does not refer to the fuel. That airflow provides all of the power, as well as most of the hot exhaust air for heat recovery, while the fuel provides the heat energy for the airflow. A 40-MWe gas turbine will use a volume equivalent of a large city's air (over 2 billion m^3) for its annual power generation.

Large inlet air filters have advanced to ensure this air is very clean to maximize performance, so that natural gas-based gas turbine systems have air quality benefits in terms of eliminating fine particulate matter (PM). Rather than producing fine PM pollution, these systems are removing most sub-micron PM, dust and volatile organic compounds from nearby ambient air.

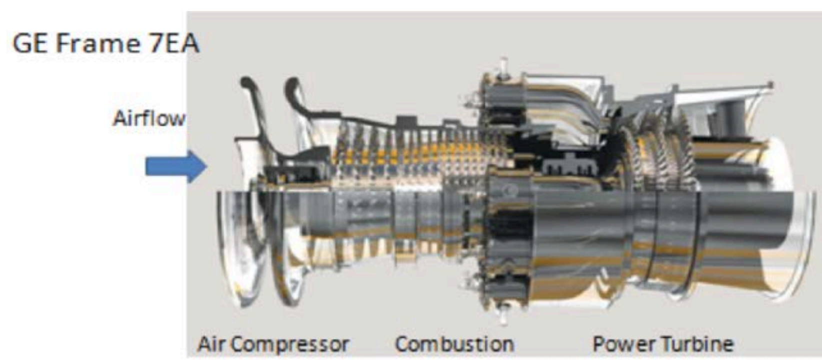
Industrial and commercial cogen facilities for today's electric and thermal generation can co-exist to support intermittent renewable energy, but they need to deal with plant cycling issues to avoid damage to equipment. Flexible gas turbine operations have been optimized for part load and start-up sequences. Newer designs have decreased ramp-up rates from 50 MW/min to 20 MW/min with redesigned steam systems, variable loading rates, and once-through steam generators.

Gas Turbine Operation for Waste Heat Recovery and Cogeneration

Gas turbines provide thermal energy in their exhaust by virtue of the exhaust gas temperature (EGT) and the mass airflow of those gases. Both of these properties depend on the type of air compression system, fuel control strategy, number of rotating shafts, and manner in which the gas turbine unit is operated when providing power to its output shaft.

When the single cycle unit is run as a base load unit at full power, (usually as a cogeneration facility) it is often operated at a maximum airflow condition through its fuel control system and fully open air compression. Power is very dependent on this airflow, and it will decline at a faster rate than airflow.

For single shaft turbines driving generators, airflow control is varied by modulating the compressor variable inlet guide vanes (VIGV) for the incoming air to the compressor. This airflow can be reduced at part power to maintain a high EGT in the 450° to 500°C range to maintain high



MS7001EA Simple Cycle Performance	60 Hz Power Generation	
Output	(MW)	85.4
Heat Rate	(Btu/kWh) (kJ/kWh)	10,420 10,991
Pressure Ratio		12.6:1
Mass Flow	(lb/sec) (kg/sec)	643 292
Turbine Speed	(rpm)	3,600
Exhaust Temperature	(°F) (°C)	998 537

Figure A4. Basic GE Frame 7EA gas turbine.

steam conditions (plus duct burning to supplement heat output). This allows the gas turbine unit to 'pretend' that it is a smaller gas turbine with lower airflow.

Units can be operated between 60% and 110% load to follow demand (lower power loads can be tolerated for short periods, but efficiency drops off too much). The VIGV control position angle is determined from the EGT feedback signal to slowly close the inlet area at part load, and to also limit the fuel supply to keep firing temperature from going too high. The Dry Low NO_x (DLN) combustion air control strategy will also affect these flexibility conditions, as the balancing act among EGT, airflow turbine temp and DLN becomes an important design topic.

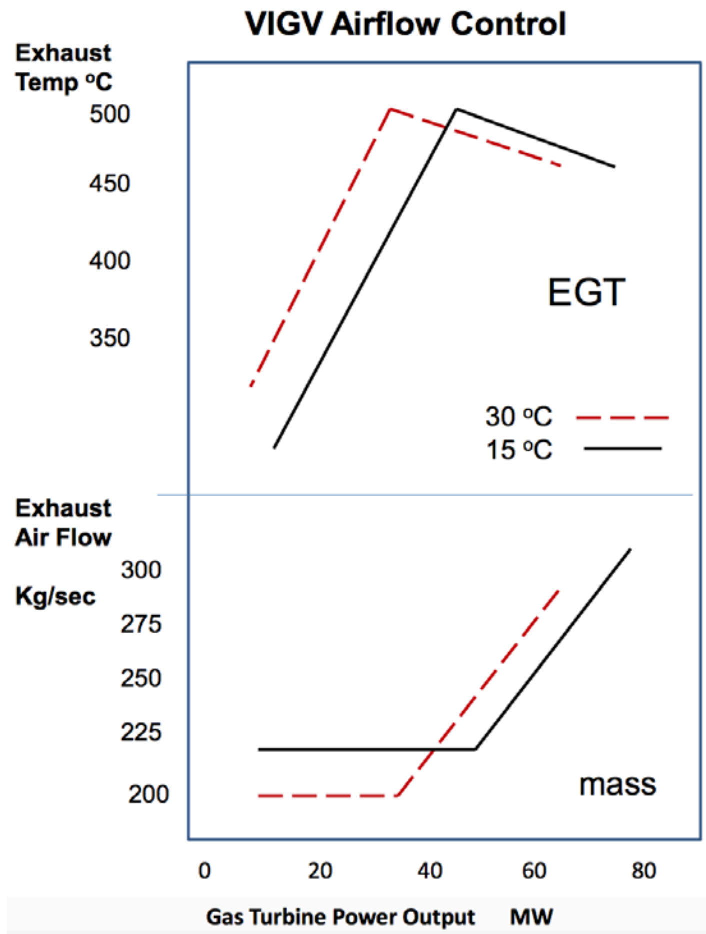


Figure A5. Variance of Airflow and EGT.

The flexibility of two shaft and twin spool aero-derivative gas turbines allows high flexibility in managing waste heat recovery, although these engines have high thermal efficiency and therefore lower exhaust temperatures than the older single shaft industrial frame units. The combination of variable compressor speeds and VIGV controls allows for more variable airflow control, an extended operating range for pipelines and for waste heat recovery.

It is normal for airflow and EGT to have an inverse relationship, so that as one increases, the other decreases. Some example relationships of EGT and airflow at various power levels at two ambient conditions are shown in Figure A5.

Duct Burning in the Heat Recovery System

For industries like oil sands and petrochemicals, large Industrial cogeneration systems can also use the flexibility of modulating airflow, and using supplementary duct burning in the heat recovery, to support intermittency on the regional power grid that has allowed

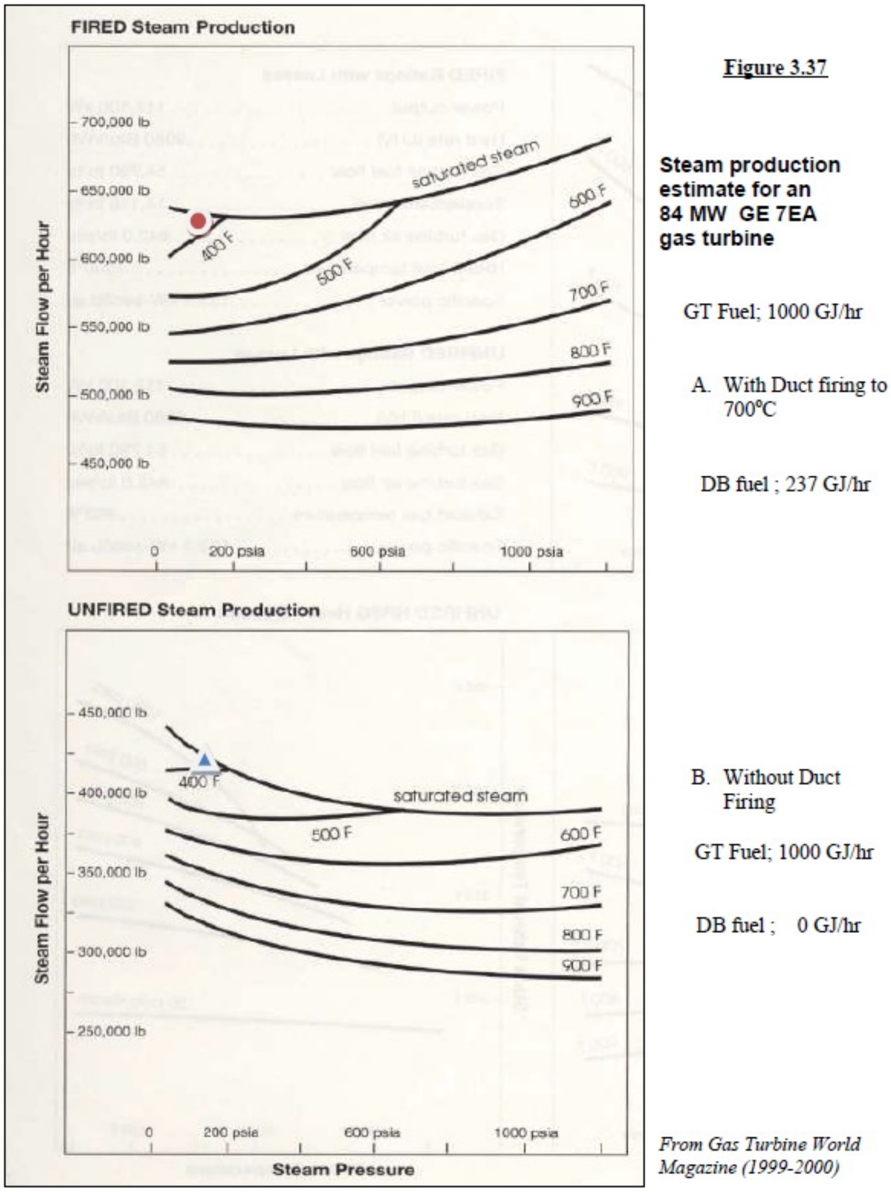


Figure A6. Cogen steam output with and without duct burning – an example of duct burning for supplemental steam production.

coal-based power to be reduced. Among many innovations for gas turbine cogeneration systems, the use of the high (14% to 16%) oxygen content of their exhaust to burn additional fuel in the heat recovery boiler is important. These duct burners can boost steam production with several benefits:

- allows smaller gas turbines for combined heat and power applications;

- provides good opportunities for aero-derivative gas turbines (which have lower exhaust temps);
- increases heat transfer and lowers stack temperatures for better efficiency;
- provides intermittent cycling flexibility; and
- allows for the use of various qualities of available fuel.

When unfired, the HRSG for a GE Frame 7EA gas turbine might produce almost 400,000 lb/hr of high-pressure saturated steam. When 24% additional gas fuel is injected into the duct burners, the steam production can rise by over 70% to almost 700,000 lb/hr. A higher 40% duct burning amount would lead to a doubling of the original unfired steam production as shown in Figure A6.

Air Pollution Prevention

Air pollutants such as NO_x and fine particulates emitted by industrial energy facilities also have an important health impact.

In 1992, Canadian national NO_x emission guidelines for stationary gas turbines were published through a national consultation to promote pollution prevention technology to prevent NO_x emissions. Waste heat recovery and cogeneration energy efficiency to minimize CO_2 emissions were also deemed important, as well as considerations of operational reliability and cost-effectiveness. The policy developed an energy output basis for the guideline, with NO_x levels directly tied to the demonstrated overall system efficiency.

This was the world's first regulatory standard for the gas turbine sector that used output energy, and helped to establish pollution prevention, combustion modifications and overall system waste heat efficiency as 'Best Available Technology.' The guideline uses an energy output basis for power and heat, in

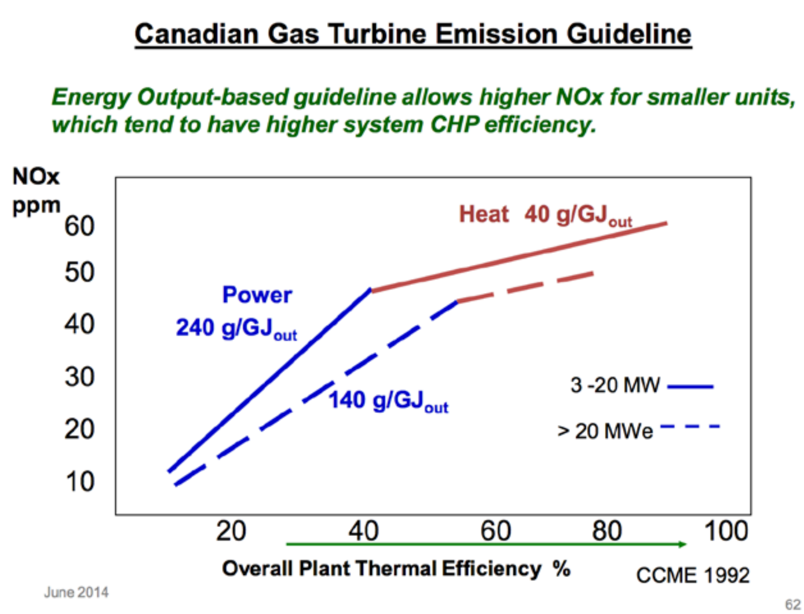


Figure A7. Canadian gas turbine emission guideline.

grams of NO_x per gigajoules of energy output. It allows higher efficiency systems to have a higher exhaust parts-per-million (ppm) NO_x concentration.

Other Considerations

The urgency of solving a number of energy and environmental challenges has become a daily imperative. Apart from traditional economic and efficiency objectives, the need for reliability and resiliency in the face of extreme weather events is coupled with the underlying problems of climate change. This is added to the health-related problems from air pollution, air toxics and certain water impacts.

Reliability. Northern projects have been susceptible to various types of regional power outages. Local combined heat and power (CHP) systems have a very important benefit of onsite energy reliability to avoid external grid outages, and this should be a consideration outside of carbon issues. Some efforts could focus on how CHP energy, emissions and allocation are done, and how oil sands onsite and Alberta grid reliability should be improved. Comprehensive climate, health and reliability benefits could be factored into balanced economic and environmental analyses and a better long-term provincial business case.

Natural gas Fuels. The hydrogen in natural gas provides over 60% of the energy value, because the hydrogen molecules in methane (CH_4) have over four times more energy per unit weight than the carbon content. This is part of the reason for the low CO_2 emissions, along with system cogeneration efficiencies of 80% to 90%, for a major GHG advantage (net CO_2 rate of 200 to 300 kg/MWh). Efficient natural gas-based energy also has very low combustion emissions of SO_2 and NO_x , and no particulates, arsenic or mercury. When natural gas is compared to coal power, output-based emissions reductions resulting in health benefits for Alberta should be about 70% on GHGs, over 90% on air pollution, and 99% on air toxics.