Integration of Nuclear Energy Into Oil Sands Projects

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Energy security and greenhouse gas reduction are thought to be two of the most urgent priorities for sustaining and improving the human condition in the near future. Few places pit the two goals so directly in opposition to one another as the Alberta oil sands. Here, Canadian natural gas is burned in massive quantities to extract oil from one of North America's largest native sources of carbon-intensive heavy oil. However, this conflict need not continue. Nonemitting nuclear energy can replace natural gas as a fuel source in an economical and more environmentally sound way. This would allow for the continued extraction of transportation fuels without greenhouse gas emissions, while freeing up the natural gas supply for hydrogen feedstock and other valuable applications. Bitumen production in Alberta expanded dramatically in the past 5 years as the price of oil rose to record levels. This paper explores the feasibility and economics of using nuclear energy to power future oil sands production and upgrading activities, and puts forth several nuclear energy application scenarios for providing steam and electricity to in situ and surface mining operations. This review includes the Enhanced CANDU 6, the Advanced CANDU Reactor, and the pebble bed modular reactor. Based on reasonable projections of available cost information, steam produced using nuclear energy is expected to be less expensive than steam produced by natural gas at current natural gas prices and at prices above \$6.50/MMBtu (CAD). For electricity production, nuclear energy becomes competitive with natural gas plants at gas prices of \$10–13/MMBtu (CAD). Costs of constructing nuclear plants in Alberta are affected by higher local labor costs, which this paper took into account in making these estimates. Although a more definitive analysis of construction costs and project economics will be required to confirm these findings, there appears to be sufficient merit in the potential economics to support further study. [DOI: 10.1115/1.3098421]

1 Introduction

The Canadian oil sands industry has grown tremendously in the past 5 years, and promises to continue in steady growth for decades to come. The oil sands are becoming an increasingly valuable natural resource, as oil prices rise and energy security becomes a North American priority. In 2006, oil sands production accounted for roughly half of Canada's total oil production, and by 2010, it is expected to represent two-thirds of the country's total production [1–3]. Over \$40 billion have already been spent on oil sands projects, and an additional \$54 billion are projected by 2012 [2,4]. (Unless otherwise stated all monetary figures are in Canadian dollars.) The total bitumen in-place in the Alberta oil sands is estimated to be about 1.7 trillion barrels, of which up to roughly 309 billion barrels are considered recoverable. Eighty percent or more cannot be recovered through surface mining and require in situ methods [1,2].

Currently, bitumen recovery is primarily accomplished either by surface mining and later extraction through thermal processing, or by in situ means such as steam assisted gravity drainage (SAGD). The economics of surface recovery is dominated by the cost of mining equipment, operations, and reclamation. The economics of in situ production is dominated by the cost of the natural gas (NG) used to make steam for injection and power for pumping. High oil prices have made both approaches profitable, supporting rapid expansion. In most cases, both of the recovery methods use natural gas as an energy source, releasing greenhouse gases into the environment.

The use of increasingly large amounts of natural gas for oil sands recovery presents a number of economic and environmental problems. Steam generation and upgrading processes will contribute large amounts of greenhouse gas emissions, while Canadian and regional environmental policies seek long-term reductions [5–9]. Large planned increases in natural gas consumption will cause Western Canada to become a net importer of gas, with potentially serious impacts on regional natural gas pricing and market volatility [10,11]. This is likely to impact not only the profitability of the oil sands business, but also the price and availability of natural gas to homeowners, commercial users, and other industries.

This paper explores the feasibility and economics of using nuclear energy to power future oil sands production and upgrading activities. Although these are more expensive to build than conventional facilities, nuclear reactors produce no operational greenhouse gas emissions and offer relatively low and stable fuel and operating costs. There are, however, several trade-offs. This paper compares the benefits and the drawbacks, and puts forth several nuclear energy application scenarios for providing steam and electricity for upgrading bitumen from both in situ and surface mining operations.

2 Energy Requirements for SAGD

SAGD fields vary significantly in their steam requirements. Some fields operate using steam generated at 9–11 MPa and 310–320°C (Suncor's Firebag and EnCana's Foster Creek), while others may use steam generated at about 6.0 MPa (275°C) with similar success.

Saturated steam is produced at sufficient pressure to support distribution and injection. After pressure drops due to friction and flow splitting (directing streams to separate well pads), the steam is closer to 4.5–6.5 MPa when it reaches an injection well. The steam to oil ratio (SOR) is a measure of the amount of steam needed in terms of cold water equivalent to produce a barrel of bitumen. A typical SOR is between 2 and 4, with the goal being at

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Table 1 SAGD steam natural gas consumption and GHG emissions (SOR=3.0)

Barrels of bitumen per day	Natural gas for steam production (MMBtu/day)	Resulting GHG emissions (CO_2e metric tons/day)	GHG emissions (CO_2e kt/yr)
30,000	40,053	2603	950
60,000	80,106	5207	1900
100,000	133,510	8678	3170
200,000	267,020	17,356	6340
500,000	667,550	43,391	15,840
1,000,000	1,335,100	86,781	31,680
2,000,000	2,670,200	173,562	63,350

[a]Table 1 assumes 1.3 Mcf of natural gas used per barrel of bitumen recovered.
[b]A conversion ratio of 65 kg CO_2 per MMBtu of natural gas burned is used.

the lower end. That may be achieved as SAGD methods are improved. The actual SOR for any given well depends on the quality of the deposit and specific geology in the region. For this analysis, steam production will be assumed to be between 6 MPa and 11 MPa saturated steam with a related SOR of 2–3. Thus, over the lifetime of a given well, one barrel of bitumen is recovered for every 2–3 barrels of steam injected (cold water equivalent).

Most SAGD project phases, where power and steam capacities are incrementally added in the Athabasca region are between 10k bbl/day and 6k bbl/day. Peak project production rates are expected to range up to about 2k bbl/day (at EnCana's Foster Creek project, for example), with most of the larger proposed projects in the range of 100K bbl/day.

In situ SAGD recovery uses about 1.0–1.5 Mcf of natural gas for each barrel of bitumen recovered [3,12–16]. An SOR of 2.5 corresponds to a natural gas requirement of 1.1 Mcf/bbl. An SOR of 3.0 is used for Table 1, corresponding to a natural gas intensity of 1.3 Mcf/bbl. (1 Mcf is equivalent to 1.027 MMBtu.)

Table 1 shows the natural gas consumption and resulting greenhouse gas (GHG) emissions per day (and per year) of varying amounts of SAGD bitumen production per day.

SAGD projects require little electric power relative to their required thermal energy. Electricity is used primarily for pumping feedwater to support required steam pressures. Sophisticated water treatment facilities can increase the electric load in some planned cases. A typical SAGD project uses about 9 kW h of electricity per barrel of bitumen produced. Table 2 summarizes the SAGD electricity requirements for various production rates of bitumen per day and the resulting GHG emissions based on the grid emissions factor [12–16].

3 Energy Requirements for Surface Mining and Extraction

The surface mining and extraction processes use about 16 kW h of electricity per barrel of bitumen recovered [15,17,18]. Roughly 10% of the electricity is used in the mining process, 80% is used for bitumen extraction and cleaning, and 10% is used for utilities and other miscellanies. Table 3 provides a summary of electricity requirements for surface mining and consequential GHG emissions of gas fired units. Heat requirements are summarized in Table 4.

Table 2 SAGD electricity supply and GHG emissions

Barrels of bitumen per day	Electricity requirement (MWe)	GHG emissions (CO_2e metric tons/day)	GHG emissions (CO_2e kt/yr)
10,000	3.75	30	11.0
30,000	11.3	90	32.9
60,000	22.5	180	65.7
100,000	37.5	300	109.5
200,000	75.0	600	219.0

[a]Based on 0.15 metric tons of CO_2 per MW h for natural gas generation and 45% electrical efficiency for combined cycle gas plant.

Table 3 Surface mining electricity supply and GHG emissions

Barrels of bitumen per day	Electricity supply requirement (MWe)	GHG emissions (CO_2e metric tons/day)	GHG emissions (CO_2e kt/yr)
10,000	6.7	53	19
30,000	20.0	160	58
60,000	40.0	320	116
100,000	66.7	533	193
200,000	133.3	1067	387

[a]Based on 0.15 metric tons per MW h for natural gas generation and 45% electrical efficiency for a combined cycle gas plant.

A review of current surface mining activity indicates that the thermal energy requirements to extract one barrel of bitumen from the mined oil sands is equivalent to approximately 1 Mcf of natural gas per barrel, or about 12 kWth per barrel per day (bpd) capacity [15,17,18]. However, since most large surface mining projects also have on-site upgraders, the majority of that requirement is provided by waste heat from the upgrader. The remainder of the heat that is provided by dedicated gas fired boilers is equivalent to about 0.28 Mcf of natural gas per barrel, or 3.5 kWth per bpd of production. Due to the typical arrangement of sharing heat between the upgrader and the extraction plant, only the extraction-dedicated energy production will be attributed to the extraction operation here. The heat that is initially provided to the upgrader will be assessed only to the upgrader to avoid double-counting.

The oil sands industry is planning to produce most of its additional future energy from natural gas at rates that can dramatically influence regional gas availability and pricing. These quantities demonstrate the size of the potential market for other forms of power and steam that can compete with natural gas.

4 Evaluation of Nuclear Energy Options

A few specific types of nuclear reactors have been proposed for use in the oil sands, namely, the Enhanced CANDU 6, the Advanced CANDU Reactors (ACRs) ACR-700 and ACR 1000, and the high-temperature gas-cooled reactors such as the pebble bed modular reactor (PBMR) and AREVA's ANTARES prismatic design. For the purpose of this study, since the PBMR is further along in development, it will be used as the reference high-temperature gas reactor.

In each case, the capacity of the nuclear reactor for producing steam has been modeled using the ASPEN PLUS™ program [19]. The analysis performed for this report is intended to determine the

Table 4 Surface mining extraction heat requirements, natural gas consumption, and GHG emissions

Bitumen (bpd)	Natural gas for steam and hot water production (MMBtu/day)	Resulting GHG emissions (CO_2e metric tons/day)	GHG emissions (CO_2e kt/yr)
10,000	2875	187	68
30,000	8627	561	205
60,000	17,254	1121	409
100,000	28,756	1869	682
200,000	57,512	3738	1364

[a]Based on 65 kg CO_2 per MMBtu NG burned (1 Mcf is equivalent to 1.027 MMBtu), mining and extraction require approximately 0.28 Mcf, as per bbl bitumen [3,15,18,20].

Table 5 ACR-700 steam supply capability (281°C steam)

Steam pressure (MPa) [21]	Steam quality [21]	Barrels of steam (CWE) per day	Bitumen bbl/day (SOR=3.0)	Bitumen bbl/day (SOR=2.0)
6.5	0.80	697,872	232,624	348,935

approximate steam production capacity for each reactor for the purpose of comparing that output to the needs of an oil sands project.

4.1 Enhanced CANDU 6. The Enhanced CANDU is a pressurized heavy water reactor (PHWR), using heavy water as both a coolant and a neutron moderator. It provides approximately 740 MWe (2064 MWth) in a two-loop primary cooling configuration with four steam generators [21–25].

At only 4.7 MPa, the Enhanced CANDU's steam output is at too low a pressure for most SAGD projects. A change in secondary steam pressure would require a complete system analysis and redesign to modify the reactor operation. A regulatory review of these changes would also be required.

Opportunities may exist for using secondary natural gas fired boilers to boost the heat content of the steam after it is heated by the CANDU, but that scenario will not be considered here. Low pressure steam assisted gravity drainage (LP-SAGD), which requires much lower pressure steam than conventional SAGD, could be a better match for the Enhanced CANDU. LP-SAGD is only beginning to be used in commercial operation, but if it is successful, it could be adopted on a wide scale due to its water and energy savings. Since the pressures required by LP-SAGD are much lower, piping the steam from an Enhanced CANDU to the outskirts of a large field might well be feasible. Since the economics of the LP-SAGD process are highly speculative at this time, it is too soon to tell whether the CANDU might prove economic in that application.

Should the Enhanced CANDU be used for electricity production or hydrogen production in a central location (e.g., Edmonton or perhaps Fort McMurray), there should be no difficulty in utilizing the reactor for its full lifetime. It would likely provide services for many oil sands projects in the region.

4.2 Advanced CANDU Reactor: ACR-700. The ACR-700 is a 753 MWe (gross), 2034 MWth plant, similar in many basic design features to the earlier CANDU reactors [21,24–26]. The secondary loop pressure in the ACR-700 is much higher than in the CANDU 6 (6.5 MPa versus 4.7 MPa), and so it is a more promising choice to provide steam to the SAGD process at useful pressures under some conditions. The reactor could potentially yield other pressures with modifications to the secondary loop, which could make it more viable.

One ACR-700 is sized to provide steam for a project of 200k–350k bpd, as shown in Table 5. However, with a steam generator outlet pressure of only 6.5 MPa, and given the large size of a field necessary to support this production, piping the steam to the outer parts of the 200k+bpd field would not be possible without significant pressure drop that would render the steam too low in pressure for traditional SAGD.

The ACR is designed to operate for 40–60 years. While the ACR-700s energy capacity would be added all at one time, it is not likely that 200k+ bpd of SAGD capacity would be installed at the same time. SAGD projects are generally installed in phases of not more than 70,000 bpd, and to install a greater capacity than needed would not be economically justified. To complicate matters further, the steam from the ACR would have to be pumped to an area large enough to sustain the 200k+ bpd production for 40 years to last the lifetime of the plant. A 10 km radius was determined to be a feasible distance to the pipe steam based on simple calculations of pressure drop and heat loss through typical insulated pipes for this application. It was determined that a realistic SAGD field of this size would not demand the steam production of an ACR-700. The reactor is simply much too large for this application, and so the ACR-700 is not suitable solely as a steam supply plant using the current in situ technology. The option of using heated steam pipes was not considered.

The ACR-700 may be a better match for projects with significant electrical power requirements, in addition to medium or low-pressure steam requirements, or for projects that require an extended use of electricity or heat for upgrading even after the local field has been depleted.

4.3 Pebble Bed Modular Reactor. The PBMR is a modular high-temperature gas-cooled reactor (HTGR) that utilizes a spherical fuel element, has high reactor outlet temperatures, passive safety features, and an on-line refueling process [27]. Operating conditions are shown in Fig. 1.

The simplest reactor configuration being considered here is one with a single PBMR reactor with two primary helium loops, each coupled to its own secondary helium loop. The secondary loop transfers heat through a steam generator, and the steam is sent to the SAGD wells for the production of bitumen [28].

Other secondary side configurations are possible. The secondary loop is chosen for this application in order to isolate the reactor from the possibility of steam ingress or contamination from feedwater impurities, and to allow normal (nonnuclear) maintenance on the steam generators during operation of the nuclear plant. The choice of two primary loops gives added reliability to the steam supply, in that a maintenance requirement in one loop may not require full shutdown, and also results in smaller components that are more easily transported to the site [28].

Steam production for a single PBMR is given in Table 6. It is important to note that in this case the PBMR would require about 33 MWe for its own electrical load, based on very preliminary calculations. Since the PBMR would not be configured to produce electricity in the steam-production-only case, electricity would need to be provided by an auxiliary source or to be purchased off of the grid. Alternatively, should electricity not be available to power the 33MWe for the steam-only case, then a cogeneration solution could be employed to produce the house load, as well as excess electricity, if needed.

The actual steam output and quality depend somewhat on the steam generator and separator designs, which may be determined by the needed output. A typical output requirement and a steam generation design have been assumed for this analysis.

One PBMR is a good size for a SAGD operation of 40k–65k bpd depending on the SOR, or two PBMRs could be used for a SAGD site with a peak output of ~80k–130K bpd. Each PBMR has its own electrical load that would need to be purchased if it was not generated onsite. This amounts to 33 MWe for each PBMR module, which includes all circulators, as well as the PBMR plant house load. While this design is not optimized, it will be used as the basis for this analysis.

Since the PBMR can be installed in modules, it can be integrated into the phased development typical of SAGD projects. One module can be installed to produce steam for the first phase of SAGD, and then, with production already underway, a second PBMR module could be added to provide steam for future development or to provide electrical power. A PBMR is designed to operate for 40 years, and given its smaller size, it would be possible to maintain bitumen production within reach of the reactor's steam supply for that length of time.

5 Nuclear Energy Integration Scenarios

The results of this analysis show that the ACR and CANDU reactors are not suitable for the most common single-project needs. These plants are not found to be good candidates for placement in a SAGD field, or in any but the largest surface mining

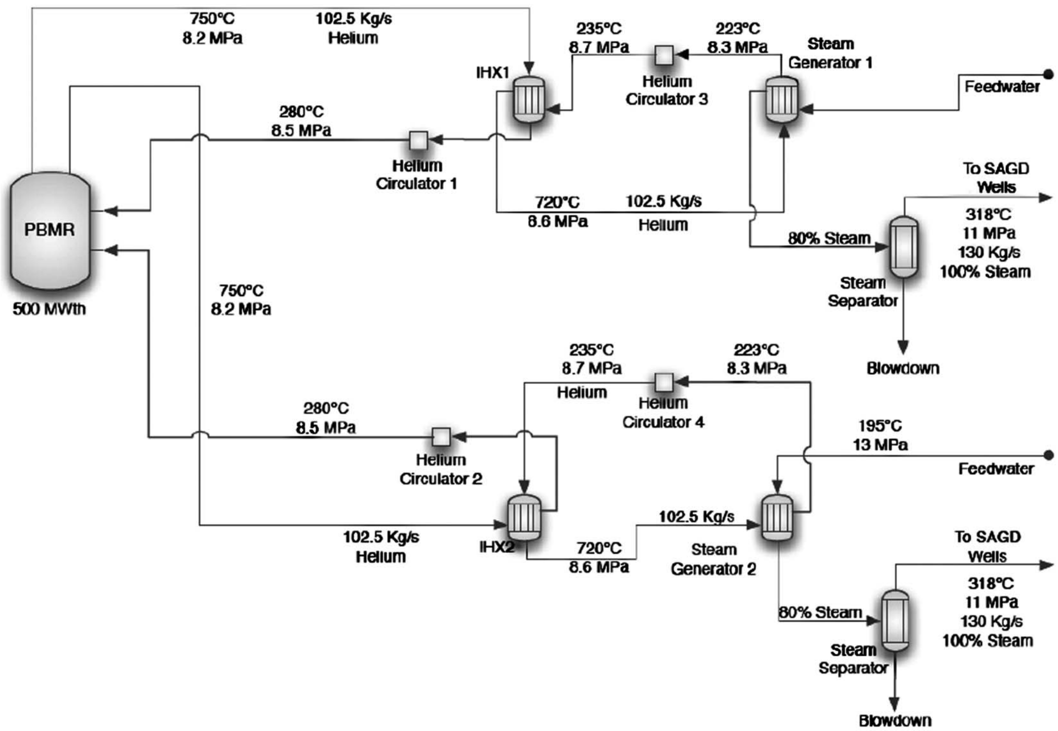

Fig. 1 Pebble bed steam supply flowchart used in analysis

operations. They are good candidates for bulk electricity production, but they should be situated where the cost of construction might be less than in the Fort McMurray area. The PBMR process heat plant is found to be an option for SAGD steam supply in addition to electricity supply, since it is roughly the size of most medium SAGD fields. Shown in Table 7 is a selection of the nuclear integration options identified in this study.

6 Economic Analysis

Economic analysis is performed for two scenarios in detail in this section: electricity and steam production. Hydrogen was not included since it was deemed that the best option was to continue to use steam methane reforming in the short term. There is a future possibility of using nuclear heat in that process, but it was not evaluated for cost effectiveness.

6.1 Electricity Production. A comparison is made among the three nuclear reactors considered in this report and a combined cycle natural gas plant (100 MWe) for the purpose of supplying electricity to the oil sands industry. The levelized cost of each option was calculated, and sensitivity analysis was performed on the natural gas price and the capital costs of the nuclear plants. The assumptions made in this analysis are detailed in Ref. [29]. A few of the key assumptions are shown in Table 8. All dollars are in Canadian dollars unless stated otherwise, and where an exchange rate was used to convert from U.S. dollars, the rate of \$0.90 USD per CAD was used. For simplicity, construction for any project was assumed to start in 2010 in the Edmonton area, where it is most likely for such a plant to be built. Regional labor adjustments were made to the base costs for overnight capital and for operations and maintenance. Overnight capital was assumed to be 40% labor related, and for the location of an electric plant in Edmonton, the labor rates were assumed to be 50% above the base rate provided for a site in Ontario for CANDUs and at a coastal location for the PBMR. Thus, the overnight capital costs were increased by 20%. Similarly, operations and maintenance (O&M) costs were assumed to be 50% labor, and so was increased to 25% over the base cost.

The analysis showed that the breakeven natural gas prices

Table 6 PBMR steam supply capability (1 module) (318°C steam)

Steam pressure (MPa)	Steam quality	Barrels of steam (CWE) per day	Bitumen bbl/day (SOR=3.0)	Bitumen bbl/day (SOR=2.5)	Bitumen bbl/day (SOR=2.0)
11.0	1.0	130,000	43,300	52,000	65,000

Table 7 Summary of nuclear energy integration options

Application	Production	Nuclear energy options
SAGD steam and electricity	50k bpd	1 PBMR
SAGD steam and electricity	100k bpd	2 PBMRs
Surface mining steam, heat, and electricity	200k bpd	One CANDU 6 or one ACR-700 or three PBMRs
Electricity	1200 MWe	ACR-1000

Table 8 Assumptions made in calculating the capital charge rate for the nuclear plants

General inflation	2.00%
Term, years	40
Federal tax rate	22.1%
Provincial tax rate	8.00%
Debt ratio	50%
Loan term, yr	40
Interest rate	8.00%
Equity return	14.75%
Prop. tax and insurance	1.50%
Tax credit rate	0.00%
Tax life, years	20
Declining balance rate	100%
Real return	12.50%
Resulting capital charge rate	0.144 in current dollars (Canadian)

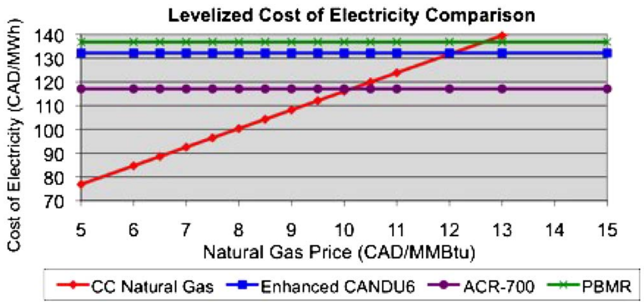

Fig. 2 Levelized cost of electricity comparison

where each of the nuclear plants is competitive with the combined cycle natural gas plant are at approximately \$10.15, \$12.10, and \$12.65 for the ACR-700, CANDU 6, and PBMR, respectively, for electricity production. This analysis assumes that natural gas prices are assumed to escalate at 2.0% above inflation over the life of these projects. These results are illustrated graphically in Fig. 2.

A sensitivity analysis was also performed on the overnight capital costs of the nuclear power plants since there is much speculation as to what the capital costs might actually be. While the cost of the natural gas plant and all other factors were kept constant, the overnight costs of the nuclear plants were all raised by 20%, 30%, 40%, and 60% in turn. This was done to show the impact of a cost overrun on the ultimate cost of the electricity produced. The analysis was performed first at \$5/MMBtu natural gas, and then at \$11/MMBtu natural gas, and the results of the \$5/MMBtu case are shown in Fig. 3.

In the \$5 gas case, none of the nuclear plants was found to be competitive at the baseline capital cost. In the \$11 gas case, the ACR-700 was found to be competitive at the baseline capital costs, but at a 20% overrun it was slightly more expensive than natural gas.

It should be noted that additional sensitivities should be considered in future economic evaluations. The cost of capital is a significant parameter affecting the cost of nuclear and other capital-intensive projects. Alternative financing mechanisms that reduce the cost of capital will have a dramatic impact on the levelized cost. Should public or government support in the form of loan guarantees, low interest loans, or low interest environmental bonds be made available, the cost of the nuclear option would be greatly reduced. In addition, the future rate of natural gas price growth is also a very important parameter, for which sensitivity studies need to be made to fully appreciate the economics of alternatives.

6.2 Steam Production. Estimating the costs of steam production plants is difficult because the cost data available publicly are generally applicable to electric plants. Adjustments were made to account for two effects. First, the movement from Edmonton (for an electric plant) to Fort McMurray (for a steam plant) was predicted to increase labor rates from 50% over base rates to 100% over base rates. Additionally, the conversion from an electric power plant to a steam plant eliminates a number of expensive systems, reducing the overall cost of the plant. For the sake of consistency, in each nuclear plant case it was assumed that the costs associated with the electricity generation accounted for 1/3 of the overnight capital costs of the nuclear plants. The cost of that equipment is dominated by the turbine-generator, moisture separators and reheaters, oil lubrication systems, and the electrical switchyard. The basis for that assumption is that the typical light water reactor has approximately a 60/40 division between the steam plant and the electricity generating plant. Thus, the assumption that the nuclear heat plant has a cost two-thirds that of the nuclear electric plant is conservative, since it is less favorable to the economics of the steam plant than a 60/40 split. The cost adjustments made to the nuclear plants are detailed in Ref. [29].

Table 9 Levels of steam production for each generation option

Plant type	Steam production (bpd)
2064 MWth enhanced CANDU 6	653,000
2034 MWth ACR-700	697,000
500 MWth PBMR	130,000

The steam production assumed for each plant is given in Table 9. The plants are rated in this case based on their thermal capacity, but the thermal capacity used was the net capacity after providing the heat needed for the house load. The cost of the steam generated from a natural gas boiler was approximated from a reference and is shown in Fig. 4 [30].

The baseline cost to produce one barrel of steam (cold water equivalent or CWE) from the nuclear reactors was \$3.02 for the Enhanced CANDU 6, \$2.49 for the ACR-700, and \$2.97 for the PBMR. The improved competitiveness of the PBMR is due to the use of all of the energy produced by the reactor in the production of steam of higher temperature and quality. For the natural gas plant, at \$5/MMBtu gas, the cost found was \$2.20. The breakeven natural gas prices were \$6.85/MMBtu for the Enhanced CANDU 6, \$5.65/MMBtu for the ACR-700, and \$6.75/MMBtu for the PBMR. These results are shown in Fig. 5. For reference, the Jun. 2007 average NYMEX natural gas price was approximately \$7/MMBtu, and the May 2008 NYMEX natural gas price was about \$10/MMBtu. Note that the ACR-700 and Enhanced CANDU 6 are not suitable for most SAGD projects due to low steam pressures and overly high capacity. The cost of steam from these reactors is shown only for comparative purposes.

A sensitivity analysis was again performed on the overnight capital costs of the nuclear power plants. While the cost of the natural gas plant and all other factors were kept constant, the overnight costs of the nuclear plants were all raised by 20%, 30%,

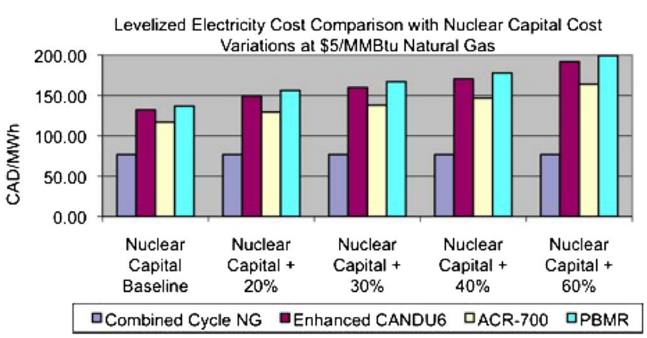

Fig. 3 Levelized cost of electricity with varying nuclear capital costs at \$5/MMBtu natural gas

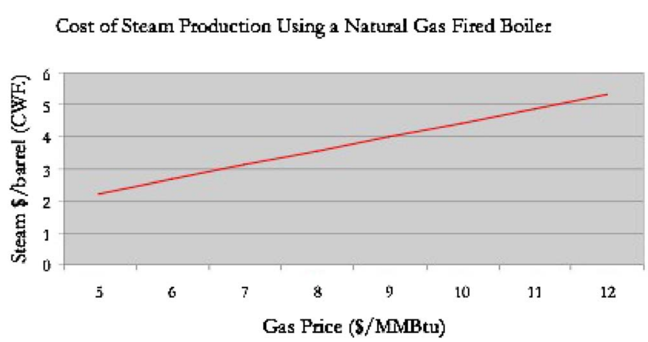

Fig. 4 Cost of steam production from a natural gas fired boiler

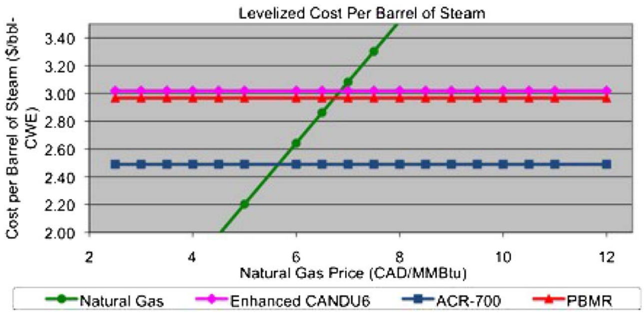

Fig. 5 Levelized cost per barrel of steam

40%, and 60% in turn. This was done to show the impact of a cost overrun on the ultimate cost of the steam produced. The analysis was performed for $5/MMBtu natural gas and for $11/MMBtu natural gas, and the results of the $5/MMBtu case are shown in Fig. 6.

In the $5 gas case, none of the nuclear plants proved to be more economic than a natural gas plant. In the $11 gas case, the results showed that the costs for producing steam with a nuclear plant were much less expensive than natural gas fired production, even when the capital costs were overrun by 60%. It is clear that nuclear energy for steam production can be competitive with natural gas at foreseeable gas prices, even when great risks are assumed in the capital costs.

Nuclear generation at the assumed costs is not shown to be competitive with natural gas for production of electricity until gas prices are as high as $10/MMBtu. The likely reasons for this distinction lie in the very high efficiencies of the natural gas combined cycle electric plant versus the lower efficiencies associated with a nuclear electric power plant. In the steam case, however, it is much simpler to utilize the full heat output of the nuclear plant, and the comparison with a once through natural gas boiler is favorable.

This economic analysis has been based on firm foundations, with capital costs that are believed to be accurate given the commodity prices at the time of their estimation. However, the recent surge in materials costs affects all large construction projects, and will likely raise the costs of any project, including coal and natural gas plants. When Duke Energy began planning for the construction of two 800 MW coal plants in North Carolina (2004), the cost estimate was for $2 billion. In 2006 it was $3 billion, and in 2007 one unit was canceled and the price for a single unit was projected to be $1.83 billion. This is indicative of the general trend of escalating prices on material costs throughout North America. When combined with the elevated labor costs of the Fort McMurray area, the resulting project will tend to be much more expensive now than may have been expected 5 years ago.

Table 10 Greenhouse gas emissions reductions in the oil sands region in representative reactor scenarios

Reactor(s)	Oil sands site	Input provided	GHG reduct. (CO_2e metric tons/yr)	Lifetime GHG reduct. (CO_2e metric tons)
2 PBMRs	100k bpd SAGD	Steam and electricity	3.1×10^6	125×10^6
ACR-1000	1200 MWe	Electricity	3.5×10^6	140×10^6

7 Greenhouse Gas Emissions Avoidance

One of the major reasons for considering nuclear energy in the oil sands business is to reduce the carbon footprint of the operations. As described, the range of nuclear applications from simple steam production to a complete integrated plant producing electricity and heat offers the capability of significant CO_2 emission avoidance by displacing natural gas or other fuels.

A 3000 MWth (1000 MWe) nuclear plant avoids the emissions of approximately 10,000 tons of nitrogen oxides (NO_x) and 32,000 tons of sulfur dioxide (SO_2) each year, in addition to eliminating over 4 million metric tons of CO_2 per year [31]. Shown in Table 10 are the potential CO_2 emissions reductions for a couple of oil sands production capacities. If nuclear were to replace natural gas in the oil sands developments announced thus far for startup between 2017 and 2020, the total reduction in CO_2 emissions in the oil sands region would be 745 million metric tons. With more nuclear plants in the future, the emissions reductions would increase with time.

These and other data are also illustrated graphically in Fig. 7. In the case of the windmill scenario, included for the reader's reference, each windmill is assumed to have a rated capacity of 1 MW (electricity supply only) and a capacity factor of 25%.

Under a carbon-pricing regime, these emissions reductions can be considered as cost savings compared with the option of fueling operations using natural gas. The present value of the lifetime emissions at the start of the project can be viewed as capital available to invest in a nonemitting technology. For example, at $50/ton CO_2e and at a 12% discount rate, 40 years of operating two PBMRs to provide steam and electricity for SAGD is worth an extra initial investment of $1.3 billion, over and above the capital cost of the presumed natural gas plant, and above any fuel price or stability advantages of nuclear. This case, as well as the others identified in this section, is illustrated in Fig. 8.

The price of carbon is a factor that increases the cost of generating heat and electricity from natural gas. Analyses were performed for the steam and electricity cases set forth in Sec. 6 with the price of carbon included as an operating cost. The resulting break-even gas prices for the nuclear technologies were progressively lower as the price on carbon rose. For electricity produc-

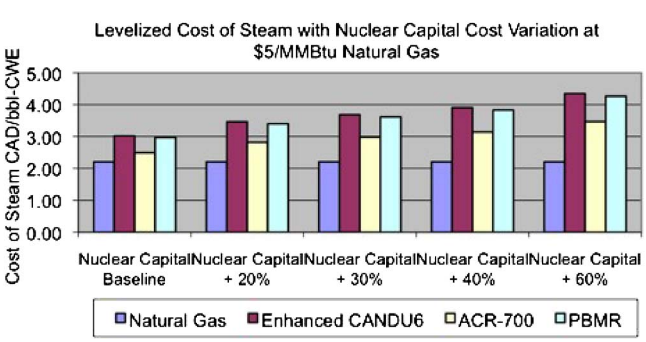

Fig. 6 Levelized cost of steam production with varying nuclear capital costs ($5 NG)

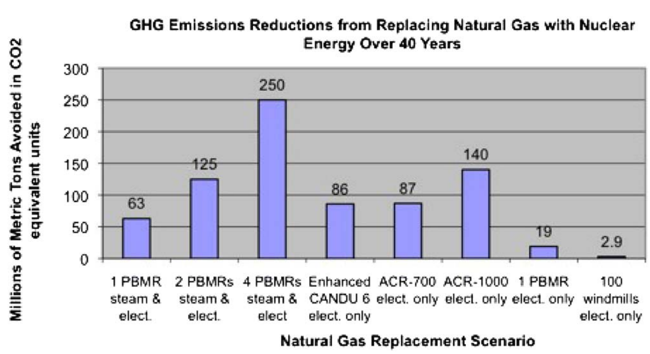

Fig. 7 Emissions reductions in replacement of natural gas with nuclear energy

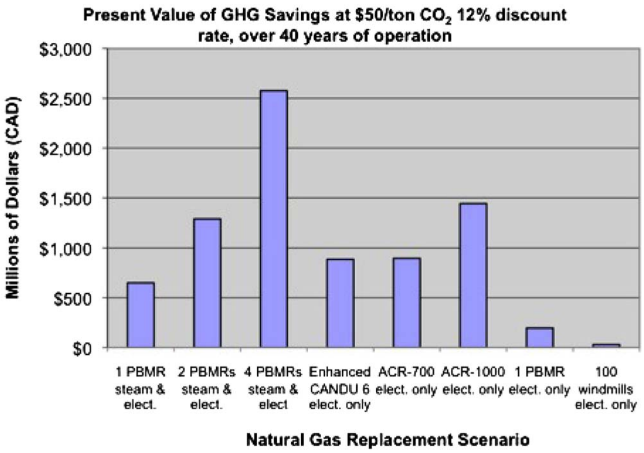

Fig. 8 Present value of emissions reductions due to replacement of natural gas with nuclear energy

tion, the ACR-700 broke even with combined cycle natural gas (CCNG) at just over \$8/MMBtu for a \$50/ton CO_2e carbon price, and at just over \$9/MMBtu for a \$100/ton CO_2e carbon price. These figures are well below recent gas prices of about \$12.

The same carbon price scenarios were explored for steam production using the PBMR for SAGD. In this case, as shown in Fig. 9, the breakeven gas price fell from \$6.50 with no carbon price to \$4.75/MMBtu at \$25/ton CO_2e, to \$3.50/MMBtu at \$50/ton CO_2e. These figures are very compelling, and show that in a carbon-tax or trading market, it would in fact be quite challenging for natural gas to compete with nuclear energy.

Carbon capture and sequestration (CCS) is being considered as another CO_2 mitigation strategy. CCS requires that a chemical plant be added to capture and separate CO_2 from the flue gas and then compress it to supercritical pressures for transport and injection into deep geological formations. CCS requires about 30% of the energy of the basic source for capture and disposal and thus adds to the cost of the final product. MIT's *The Future of Coal* report found that the costs associated with carbon capture for a supercritical pulverized coal plant equated to a carbon cost of \$40/ton CO_2e [31]. An update to the study has found a higher carbon cost of \$52/ton CO_2e [32]. This does not include the costs of sequestration, which would contribute additional costs.

The MIT study also found that there are still a number of broad concerns regarding technical integration of CO_2 capture storage and sequestration technologies in large production operations. In addition, concerns about the injection of CO_2 in terms of leakage and ultimate long-term safety of geological disposal need to be addressed. The use of carbon sequestration will require new regulatory structures and the consideration of environmental and potential safety risks of disposing of high-pressure carbon dioxide in the ground [31].

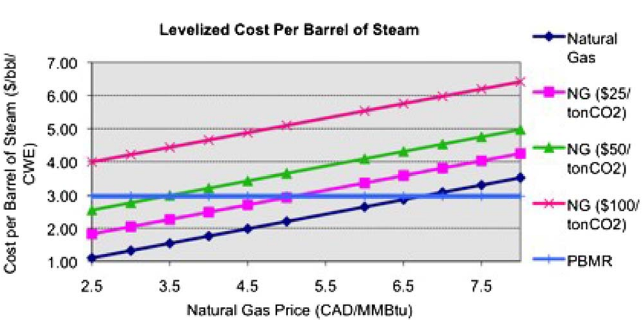

Fig. 9 Levelized cost of steam with carbon pricing

8 Construction Challenges

The logistical difficulty of transporting large nuclear reactor components to the sites in Alberta was analyzed for technical feasibility, although not for cost. In general, items that could be shipped by rail from Duluth, MN would be traveling the same route that many other large oil-sands-bound components have traveled. There is some uncertainty at this time about the possibility of transporting some of the largest components by rail, and while it is sure to be expensive, the possibility of establishing a barge route from the Beaufort Sea down to Fort McMurray is being actively explored. This would enable the shipment of virtually any size component [33–35].

Construction in the Fort McMurray area poses additional challenges that are well understood by the industry. These complications for the construction phase include seasonal weather patterns and the current high demand for skilled labor. It is not clear whether the current trend to very high labor costs will abate over the next decade as growth rates stabilize and the labor market adjusts [36–42].

The CANDU reactor construction includes the laying of a large amount of concrete, and for the best results, this should not be done during the coldest times of the year. Nuclear reactors typically require extensive welding that must meet particularly high standards, and the shortage of welders in the oil sands region would certainly be a challenge for nuclear construction. Nuclear construction would face the same challenges affecting other developments in that region.

9 Licensing

The nuclear licensing process in Canada was found to be fairly simple and technology neutral given the recent adjustment to risk-informed standards. While the Canadian Nuclear Safety Commission (CNSC) is more equipped to accommodate a CANDU-based licensing request, it will need to allocate resources to increase staffing for any serious licensing project, or the process could be delayed. The high-temperature gas reactor could be licensed in Canada based on generic functional risk-informed safety requirements, although the lack of existing expertise regarding HTGRs within the CNSC would lead to a longer licensing process. New nuclear plants will likely take 5 years or more to go through the licensing process for the first time [43–50].

10 Conclusion

The purpose of this paper has been to assess the feasibility, economics, and possible advantages of using nuclear energy in the oil sands industry based on typical conditions in the Fort McMurray region. The nuclear reactor technologies assessed are two Canadian reactors (the Enhanced CANDU 6 and the ACR-700) and a high-temperature gas reactor. The South African designed pebble bed modular reactor was chosen for this analysis, since it is the most developed.

Several specific nuclear energy applications were assessed for steam-only and steam and electricity production. In the context of steam-only production for SAGD, it was found that the steam pressure of the CANDU reactors was too low, and the size of the reactors was generally too large for typical deployment within a 10 km radius well field.

The smaller 500 MWth high-temperature pebble bed gas reactor proved to be well-suited to the steam production for two reasons. First, the steam pressures produced by the reactor are at or around the industry standard. Second, the size of the reactor is compatible with placement in a typical SAGD project. Although the PBMR was used as an example in representing the high-temperature gas reactor, other high-temperature gas reactors, such as the AREVA ANTARES or General Atomics GT-MHR, could be used but require more development.

In the surface mining application, the reactors were analyzed for their suitability to provide heat and electricity to a surface mining and extraction project. In this case, the steam pressures required of any of the processes are within the operating range of the Enhanced CANDU 6, and so it could once again be considered. The PBMR again proved to be highly versatile, and could certainly be a good fit for most medium to large surface mining projects. The CANDU 6 and the ACR-700 were found to be better sized for a surface mining operation with a production of about 200,000 barrels per day of bitumen. This is of great interest, since that is a very typical size for a surface mining project. In this case, however, the reactor would produce excess electricity that would need to be sold to other companies in the region.

Electricity could be produced for the industry by any of the reactors. Currently there is an excess of electricity generation in northern Alberta, so unless that changes, it may not be sensible to introduce a large electrical power plant.

The economics of electricity production using nuclear power were found to be favorable at natural gas prices of above $10/MMBtu. The breakeven natural gas prices for steam production were $5.65/MMBtu for the ACR-700, $6.85/MMBtu for the Enhanced CANDU 6, and $6.75/MMBtu for the PBMR. All of the breakeven prices fell when a price was put on CO_2, with nuclear electricity practical at $9/MMBtu and steam at $3.50/MMBtu, when carbon was valued at $50/ton CO_2e.

The replacement of the natural gas and electricity supply to a 100k bpd SAGD operation with nuclear energy could reduce emissions in the region by 3.3 million metric tons of CO_2e per year of operation. A 200k surface mining operation supplied with nuclear energy would reduce CO_2e emissions by 3.1 million metric tons per year in the oil sands region. Should an ACR be installed purely to provide electricity to the region, the CO_2e emissions reduction would be 2.1 million metric tons per year for an ACR-700, and 3.5 million metric tons per year for an ACR-1000. 3.5 million metric tons of savings could be worth nearly $1.5 billion (presently valued at a 12% discount rate over a 40 year lifetime, at $50/ton CO_2e).

In summary, based on this analysis, it appears that the integration of nuclear energy in the oil sands business is a viable path forward on many levels: feasibility, flexibility, economics, CO_2 emission reductions, and operability.

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