Nuclear Technology & Canadian Oil Sands: Integration of Nuclear Power with In-Situ Oil Extraction

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Abstract - *This report analyzes the technical aspects and the economics of utilizing nuclear reactors to provide the energy needed for a Canadian oil sands extraction facility using Steam-Assisted Gravity Drainage (SAGD) technology. The energy from the nuclear reactor would replace the energy supplied by natural gas, which is currently burned at these facilities. There are a number of concerns surrounding the continued use of natural gas, including carbon dioxide emissions and increasing gas prices. Three scenarios for the use of the reactor are analyzed:(1) using the reactor to produce only the steam needed for the SAGD process; (2) using the reactor to produce steam as well as electricity for the oil sands facility; and (3) using the reactor to produce steam, electricity, and hydrogen for upgrading the bitumen from the oil sands to syncrude, a material similar to conventional crude oil. Three reactor designs were down-selected from available options to meet the expected mission demands and siting requirements. These include the Canadian ACR-700, Westinghouse's AP 600 and the Pebble Bed Modular Reactor (PBMR). The report shows that nuclear energy would be feasible, practical, and economical for use at an oil sands facility. Nuclear energy is two to three times cheaper than natural gas for each of the three scenarios analyzed. Also, by using nuclear energy instead of natural gas, a plant producing 100,000 barrels of bitumen per day would prevent up to 100 megatonnes of* CO_2 *per year from being released into the atmosphere.*

I. INTRODUCTION

This report details the feasibility of integrating a nuclear power plant with Steam-Assisted Gravity Drainage (SAGD), an oil extraction technology currently used in Canadian oil sands projects. Canadian oil sands deposits represent as much as one-third of the world's known oil reserves [1]. Nearly all Canadian bitumen is located in the Province of Alberta, where the three main reservoir locations are Athabasca, Cold Lake, and Peace River. Currently, natural gas-fired plants provide the energy for the processing of the bitumen, but concerns are heightening within the industry over volatile natural gas prices and depletion of the natural gas reserves. Another drawback to using natural gas plants in oil sands is the magnitude of greenhouse gas emissions produced. These emissions limit Canada's effectiveness in lowering the country's total emissions under the Kyoto protocol and could prove to be expensive for oil sands development companies. Nuclear power is an emission-free alternative to natural gas energy to provide heat and steam for the purposes of in-situ extraction, electricity production, and hydrogen production.

II. BITUMEN EXTRACTION AND PROCESSING

Oil sands are a mixture of sand, clay, water, and bitumen (viscous heavy oil). The oil sands deposits in Canada are a major source of bitumen, but, unlike conventional oil, bitumen is too viscous to pump to the surface and has a much higher carbon-to-hydrogen ratio. The oil sands industry faces challenges in finding ways to recover the bitumen from the oil sands and also in upgrading the bitumen to higher quality oil [2].

The two general classes of oil sands recovery are surface mining and in-situ. In open-pit mining, the oil sands ore is recovered above ground with heavy-ton trucks and electric or hydraulic shovels. The ore is then sent through an extraction plant where the bitumen is separated from the other components of the oil sands. For in-situ methods, however, most of the bitumen is separated from the oil sands underground by thermal means. The bitumen is then pumped to the surface for further processing. Approximately 80% of the deposits in Canada are too deep for surface mining and can only be recovered by in-situ methods [3].

For SAGD, two horizontal wells are drilled into the underground oil sands deposit as shown in Figure 1. The horizontal length of the wells ranges from 500 to 1000 m and the distance between the top and bottom wells is about 5 m [4]. The well depth can be as shallow as 40 m, but the actual depth of the pipes varies depending on the depth of the oil sands deposits [5]. The wells are slotted to allow the passage of steam and oil. Steam is blasted into the injection well on top and rises up to form a steam chamber.

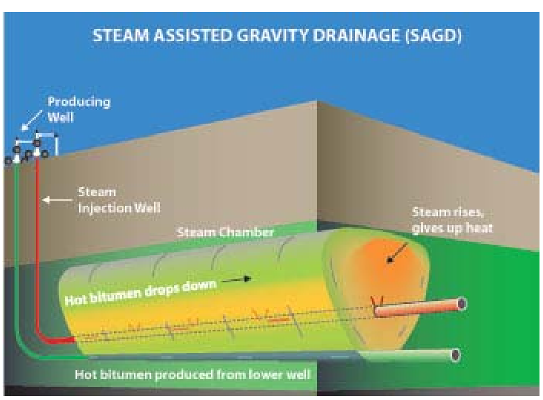


Figure 1: Schematic of SAGD [Source: 6]

The steam expands to the outer boundaries of the steam chamber and condenses at the interface. The heat conducts to colder bitumen at the interface, lowering its viscosity, and causing it to separate from the attached sand. The condensate, along with the bitumen, drains to the bottom production well by the force of gravity. This emulsion of bitumen, water and steam is pumped up to the surface to a processing facility. The steam chamber grows upwards and sideways as the oil is drained out as shown on Figure 2. [2].

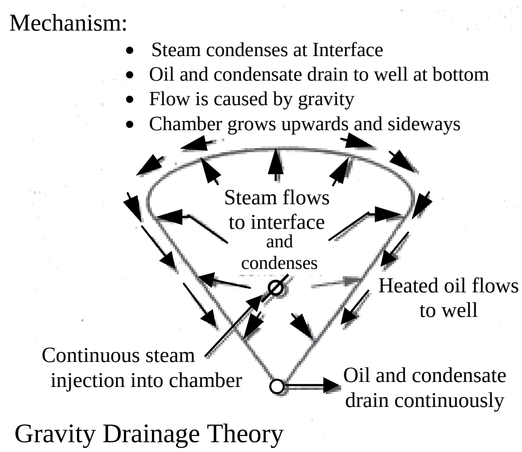


Fig. 2. Steam Assisted Gravity Drainage (Source: [2])

Some sand is present in the emulsion, but most remains in the reservoir. A processing facility converts this emulsion into diluted bitumen (dilbit), which has a lower viscosity for transportation. [4, 7] Further upgrades convert the dilbit into a product similar to conventional crude oil called synthetic crude (syncrude). The dilbit can either be shipped offsite to a central upgrading facility, or it can be upgraded at the same site where it is extracted.

With the exception of labor costs, the largest expense for both open-pit mining and in-situ projects is energy [5]. A recent Canadian study shows that nuclear power is competitive with natural gas in providing the energy demands of oil sands projects [5]. The increasing oil production rates in the Athabasca region enhance the feasibility of using nuclear power plants to meet the energy needs [5]. Both mining and in-situ projects have large energy requirements for site operations and process heat requirements for the production of high-pressure steam and hot water for bitumen purification and/or upgrading.

III. OVERVIEW OF CURRENT METHODS

Large amounts of natural gas, electricity, transportation fuels, and hydrogen are consumed in the process of recovering and upgrading bitumen from oil sands [9]. As the price of natural gas continues to increase, cogeneration facilities are becoming more popular because they are better suited for mining and upgrading. Cogeneration systems simultaneously produce electricity and thermal energy from a single facility, often using gas turbines with heat recovery steam generators.

Historically, prices of natural gas have been low in Alberta, leading oil sands projects to become dependent on it as a fuel. As the oil sands industry has grown, so has the demand for natural gas as has the price of natural gas. At this pace, oil sands projects will not be able to sustain their dependence on gas due to supply and price constraints for economic recovery. [9]

Perhaps the largest environmental issue in the oil sands industry is the emission of green house gases, including CO_2, CH_4, and N_2O. In-situ oil sand extraction plants using natural gas as fuel also emit NO_x, VOCs, H_2S, CO, O_3, PAH, SO_2, and SCs, all of which are non-greenhouse gases, in addition to particulate matter and other trace air compounds [10]. If Canada is to meet its Kyoto protocol emission targets, major expansion of the oil sands fields using natural gas as the fuel for extraction and processing is not feasible.

IV. OIL SANDS PROCESSING OPTIONS

Three different production configurations have been analyzed from the energy perspective. The focus of this analysis is to identify the most economic and sustainable long term energy source for the extraction of oil from oil sands. In so doing, three scenarios were selected to capture the energy needs expected for each of the scenarios defined to identify which energy source - nuclear or natural gas - might be the best suited and most economic for the mission at hand. The nuclear scenarios were further subdivided into alternative nuclear technologies for each of the scenarios allowing one to select, based on economics, the best heat source for each scenario or application. The scenarios involve (1) the production of bitumen only; (2) the production of bitumen and electricity; and (3) the production of bitumen, electricity, and hydrogen for upgrading. The reference design was for a plant with a 100,000 bbl/day bitumen processing capability. It is expected that smaller plants could be sized accordingly depending on the nuclear option selected.

Option 1 - Bitumen Only

The first option is for a facility that merely produces the process heat necessary to extract the bitumen from the oil sands. Shown on Figure 3 is a simple schematic for Option 1. Electricity from the existing grid would have to be purchased to support plant and processing functions. Additionally, the bitumen would have to be diluted and piped to upgrading facilities at another location for refining.

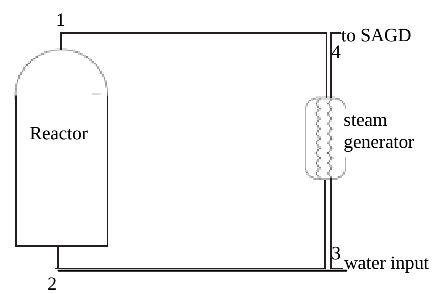


Fig. 3. Reactor for Process Heat

The energy requirements for a straightforward SAGD plant of 100,000 bbl capacity are a function of the quality of the oil sands field. Depending upon the performance of the field various pressure and process heat requirements can be established as shown in Table I. This process heat requirement determines the size of the natural gas or nuclear power station.

TABLE I
Process Heat Thermal Energy Requirements

	2 MPa	6 MPa
Low Performance	1,230 MWth	1,264 MWth
High Performance	820 MWth	843 MWth

Energy requirements were calculated using information in [11].

Option 2 - Bitumen plus Electricity

A second production scenario is the cogeneration of thermal power and electricity to meet the electric demands of the plant without requiring an existing, accessible power grid. The bitumen must still be sent offsite to be refined.

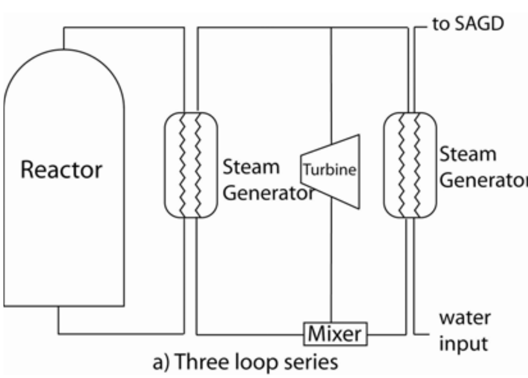
This scenario requires that in addition to the energy required for bitumen extraction, electricity needs for the bitumen processing plant, local infrastructure and utilities would be needed [11]. Shown on Table II are the anticipated electric requirements for a plant of this size [11].

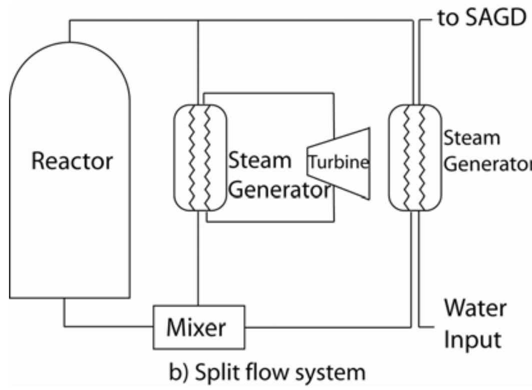
Figure 4 shows three possible configurations that ultilize a reactor to provide process heat and electric power for the bitumen extraction. The choice of the optimum configuration will depend on the reactor technology selected and cost.

TABLE II
Onsite Electricity Demands

Area	Connected Load	Average Demand
Mine	27	20
Bitumen Extraction and Cleaning	200	150
Utilities and Offsides	44	33
Infrastructure	1	1
Total	**272 MWe**	**204 MWe**

Electric loads calculated using information in [11].





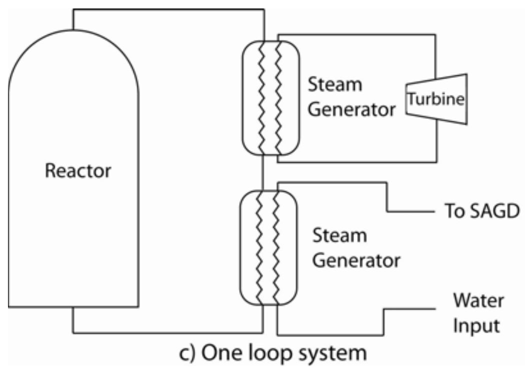


Fig. 4. Options for electricity production systems

Option 3 - Bitumen, Electricity and Syncude

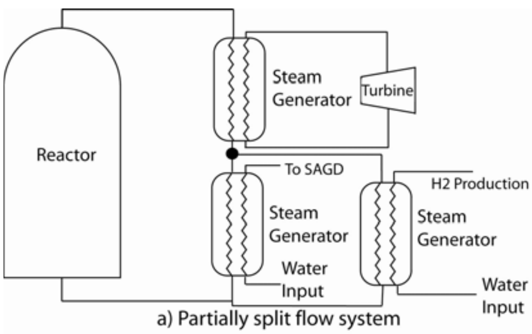
In the third and final scenario, a self-contained facility produces its own electricity and process heat, and refines the bitumen onsite to produce synthetic crude oil (syncrude). Using High Temperature Steam Electrolysis (HTSE), the facility produces hydrogen, an essential component in bitumen refining, and upgrades the bitumen to syncrude. HTSE was chosen as a hydrogen production method to avoid any dependence on natural gas, unlike processes such as steam methane gas reforming, in addition to cost and environmental considerations.

The cumulative electricity requirements are summarized on Table III for a 100,000 barrel per day syncrude plant. Estimates for electricity requirements for the HTSE plant were obtained from [12, 13, 14].

TABLE III
Onsite Electricity Requirements

Area	Connected Load	Average Demand
Mine	27	20
Bitumen Extraction and Cleaning	200	150
Upgrader	115	86
Utilities and Offsites	44	33
Infrastructure	1	1
Total	**387 MW**	**290 MW**

Shown on Figure 5 are several options for the production of process steam and electricity for this integrated facility. As in Option 2, the choice of the nuclear technology will depend on its capability for the mission and cost to produce the needed energy.



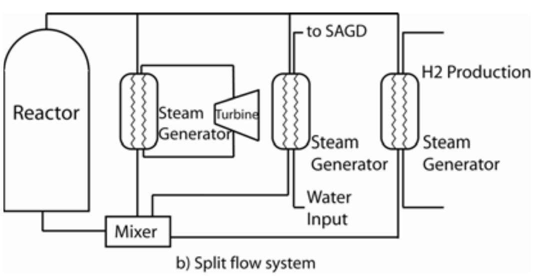


Fig. 5. Options for hydrogen and electricity production systems.

Nuclear Reactor Options

All currently available and near-term reactor options were considered in this study. A down-selection process was used to determine which reactors had the proper characteristics in terms of power generation, ease of siting, construction, and operation in the environment of Alberta, Canada. The reactors best suited for the oil sands applications were: Westinghouse's certified AP600 pressurized light water reactor with a 1,933 Mwth/610 Mwe capacity, Canada's under-development pressurized heavy water reactor with a 2,034 Mwth/703 Mwe capacity and South Africa's proposed high temperature helium-gas-cooled Pebble Bed Modular Reactor (PBMR) with a 400 Mwth/165 Mwe capacity.

Since Canada holds a substantial amount of the world's bitumen, reactors that are easily licensable in Canada are desirable, thus explaining the appeal of the ACR-700 and the AP-600; Canada has significant licensing experience with heavy water reactors (although the ACR-700 is different in some substantial areas) and the AP-600 is already certified in the US. On the other hand, onsite hydrogen and upgrading favors the use of a high temperature nuclear reactor, such as a PBMR.

Table IV summarizes the reactor options for each scenario. As can be seen, all the reactor options can be used with each scenario, but with varying thermal and process heat efficiencies which will affect the economics of the operation. Economics are discussed in Section VII. Table IV only addresses the capacity of the units and does not optimize the process cycle or efficiency of operation.

TABLE IV
Number of Reactors Required
for Each Scenario

Scenario	ACR-700	AP600	PBMR
Bitumen Only	1	1	4
Bitumen and Electricity	1	2	5
Bitumen, Electricity, and Hydrogen	2	2	8

Thus, to suit the needs of a 100,000 bbl/day plant, 1-2 AP600's, 1-2 ACR-700's, and 4-8 PBMR's are necessary, depending on the production scenario desired. Further optimizations can be made to scale the production to a specific number of reactors as desired. The aim of the project was to provide flexibility both in size and operation of the reactors to allow for growth in the oil sands field and operation in partial power configurations. This was most easily accomplished using smaller power modules, hence the need for multiple plants. In addition, the financial outlay for the smaller units would be much less, allowing for a gradual expansion in capacity.

V. ECONOMICS

Although the processing plants that utilize nuclear energy as a power source offer environmental benefits, the nuclear alternative must be shown to be economically competitive with the natural gas-fired option. This analysis compares the nuclear option costs with the natural gas cost for equivalent energy and electricity needs. All costs in this section are in US dollars (US$).

The economic advantage of using natural gas cogeneration plants to heat steam for in-situ extraction methods was apparent in the 1980s and 1990s when natural gas was cheap and abundant. As the oil-sands production industry has become more heavily reliant on natural gas, it now appears that the costs and supply of natural gas may force the industry to consider a more economically viable option. The natural gas market over the past ten years has been characterized by its volatile price and increasingly tightened supply and demand chain. Figure 6 shows a recent history of the price of natural gas. During this time period, the price of natural gas has increased at a remarkably high rate. The most recent price of natural gas recorded by the NYMEX index was more than $8.50 mmBtu in January 2006 [15] with fall 2005 peaks at over $13 mmBtu.

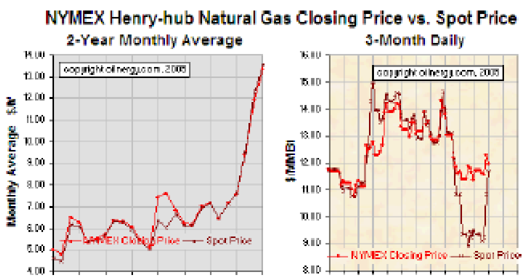


Fig. 6. Natural Gas Prices (Source: [15])

The demand for oil has been steadily increasing, not only in North America, but also throughout the world [9]. This has been due to a number of factors, ranging from exponential industrial development in emerging superpowers such as China and India, as well as increased power demands due to higher standards of living and economic production in already-developed countries. The supply of oil, on the other hand, is finite and thus these resources are becoming increasingly precious. The increasing price of oil allows alternative sources of oil production such as oil sands to be developed. However, if the price of gas increases as well, the margins available to produce an economic oil product go down. It is highly unlikely that the current rate of natural gas production will grow at a rate anywhere near the growth in demand. The ultimate result will be increasingly volatile gas prices rising at a rapid pace to satisfy market demand. It is for this reason that the nuclear option is being considered for oil sands applications.

There are four main types of costs that are important in the calculation of total system cost for both the natural-gas fired and nuclear facilities:

- Capital Cost
- Operating & Maintenance Cost
- Fuel Cost
- Decommissioning Cost

The three scenarios, where only bitumen is produced in the absence of electricity production, where bitumen is produced with electricity at the plant, and where bitumen, electricity, and hydrogen are all produced, are analyzed for energy costs for all options including natural gas.

The economic comparison considers only the energy costs for each option assuming that that processing facilities, in the case of bitumen extraction and processing, will be the same for each of the energy sources. The purpose is to focus on the energy production options and not the total cost of the end products, be they bitumen, dilbit or syncrude.

V.1. Scenario 1: Bitumen Production Only

An existing source of electricity must be available, as electricity will be necessary both for plant operations and to upgrade the bitumen. Hydrogen costs will also be incurred as part of upgrading. Since these costs are incurred regardless of the type of processing plant, whether natural gas-fired or nuclear-powered, the costs are the same across the board.

Bitumen production demands require 1260MJ/sec, which corresponds to 3.688 x 10^7mmBtu/yr. A conservative estimate of $8.00/mmBtu was used as an approximation of future gas prices. As such, the required fuel cost for a natural gas-fired plant is approximately $295M/yr. Assuming a discount rate of 10% and a 30-year plant lifetime, the NPV of the fuel costs of the natural gas-fired plant is $2781M. Assuming that electricity is purchased off the grid and hydrogen is purchased for upgrading, the additional NPV costs incurred are $1053M and $2744.2M, respectively. The current capital cost is $120M, and the NPV of operating and maintenance cost is $75.4M. Assuming that the plant will be decommissioned in 30 years, the NPV of the decommissioning cost is $0.5M. Similar analyses can be performed on the various nuclear reactors. Table V summarizes the findings.

TABLE V
Total Cost Comparison for Scenario 1

	Natural Gas	PBMR	ACR-700	AP600
Capital Cost	$120M	$458M	$714.3M	$607.4M
Operating and Maintenance Cost	$75.4M	$136.7M	$461M	$445.9M
Fuel Cost	$2781M	$225.3M	$90.5M	$145.2M
Decommissioning Cost	$0.5M	$9.9M	$5.9M	$20.3M
Electricity Cost	$1053M	$1053M	$1053M	$1053M
Hydrogen Cost	$2744.2M	$2744.2M	$2744.2M	$2744.2M
Total Cost	**$6774.1M**	**$4627.1M**	**$5068.9M**	**$5016M**

Sources: [13-14, 16-25]

V.2 Scenario 2: Bitumen and Electricity Production

Under Scenario 2, the electricity would be produced on site. The additional fuel costs incurred for the options are less than the costs required to purchase the electricity from the existing grid. The cogeneration of electricity with the process heat is appealing in either application, whether nuclear or natural gas-based.

TABLE VI
Total Cost Comparison for Scenario 2

	Natural Gas	PBMR	ACR-700	AP600
Capital Cost	$120M	$717.9M	$1190.5M	$1012.3M
Operating and Maintenance Cost	$75.4M	$169.7M	$461M	$445 .9M
Fuel Cost	$3959.4M	$285.6M	$114.1M	$184.8M
Decommissioning Cost	$0.5M	$12.4M	$5.9M	$20.3M
Hydrogen Cost	$2744.2M	$2744.2M	$2744.2M	$2744.2M
Total Cost	**$6899.5M**	**$3929.8M**	**$4515.7M**	**$4407.5M**

Sources: [13-14, 16-25]

V.3 Scenario 3: Bitumen, Electricity, and Hydrogen Production

Since the most predominant method of hydrogen production today is steam methane reforming, the natural gas can be used to produce hydrogen. Additional fuel costs in Table VI reflect the extra natural gas necessary to produce the hydrogen required for upgrading. Nuclear options have been selected to utilize high temperature steam electrolysis (HTSE), which takes advantage of the addition of heat to reduce the electric demands necessary for electrolysis. The cost for the HTSE plant in the nuclear cases has been calculated from an estimated annual cost of $80M, which was extrapolated from existing data concerning the cost of such plants [14].

TABLE VII
Total Cost Comparison for Scenario 3

	Natural Gas	PBMR	ACR-700	AP600
Capital Cost	$120M	$1274.9M	$2145M	$1824M
O & M Cost	$75.4M	$268.7M	$737.2M	$713.6M
Fuel Cost	$5879.7M	$499.6M	$199.8M	$322.4M
Decommissioning Cost	$0.5M	$19.6M	$17.4M	$32.5M
HTSE Plant Cost	----------	$754.2M	$754.2M	$754.2M
Total Cost	**$6075.6M**	**$2817M**	**$3853.6M**	**$3646.7M**

Sources: [13-14, 16-25]

The preceding examples show the viability of nuclear energy in comparison with its natural gas counterpart. Nuclear energy offers clear benefits in terms of fuel costs over the lifetime of a 30 year plant.

However, the relative advantages of the scenarios are difficult to discern. By addressing the applicability of nuclear power for the various production scenarios in terms of per unit cost, the advantages of nuclear power in each scenario become evident (Table VIII).

TABLE VIII
Summary of Results

		Natural Gas	PBMR	ACR-700	A P600
Process Heat + Electricity (Total Cost per unit steam, $/m^3$	Make Electricity	9.321	2.660	3.974	3.731
	Buy Electricity	9.040	4.224	5.215	5.096
Hydrogen (Cost per unit bitumen, $/bbl)	Make Hydrogen	1.754	1.636	1.901	1.811
	Buy Hydroden	2.506	2.506	2.506	2.506

Sources: [13-14, 16-25]

In summary, nuclear technology presents a huge economic advantage over a natural gas facility, and by using the nuclear option, production of electricity and hydrogen will also be viable internally rather than relying on outside sources for these services.

VI. LICENSING

One of the obstacles to nuclear energy plant deployment is the concern regarding the licensing process which can be lengthy and costly. The Canadian Nuclear Safety Commission (CNSC) regulates all activities related to the use of nuclear energy and nuclear substances in Canada. The CNSC reviews all licensing applications and supervises the execution of its decisions. Licensees are continually monitored to ensure their compliance with the national regulations, including the safety requirements, as set out through the Nuclear Safety and Control Act (NSCA) and its associated directives, and Canada's international commitments on the peaceful use of nuclear energy.

While the only operating nuclear reactors in Canada are pressurized heavy-water reactors (CANDUs), licensing regulations do not prohibit or privilege any reactor design specifically, and every design has to go through the same application process, which is reviewed on a case-by-case basis [8]. Unlike the United States Nuclear Regulatory Commission (NRC), the CNSC does not have a design certification process. Licensing applications are thus specific to the facility and not to the reactor design. However, an optional pre-licensing review of a design is possible, which would determine if there are any fundamental barriers to licensing the design in Canada under the NSCA.

For the scenario in which hydrogen would be produced, along with process heat and electricity, additional safety issues must be addressed, which will affect the licensing process. While Canada has no specific regulations for this case, the potential effects of any hazardous substances, such as hydrogen, must be discussed as part of the requirements for the license applications, as well as measures to prevent these.

According to [12], “Regardless of how nuclear power is converted into hydrogen, no special safety features arise, provided there is enough physical distance" between the nuclear and hydrogen plants. In other words, the separation distance is the most important factor to be considered when co-locating the plants, and the license applicant must be able to show that the selected value is enough to address the related safety concerns. The necessary separation can be reduced by building a barrier between the plants, constructing blast panels near the hydrogen plant to dampen overpressure events, or building either plant underground.

VII. NUCLEAR WASTE MANAGEMENT

Another concern about nuclear plant deployment is the issue of disposal of nuclear waste. Nuclear waste storage in Canada is a well-established undertaking. Low level waste is stored primarily in southern Ontario and in Fort

McMurray in Alberta (in close proximity to the oil sands fields). High level waste and spent fuel can be stored for 5 to 10 years in wet storage, and then for 100 years in dry storage containers. Canada's long term disposal plan calls for a deep geological repository, possibly located in the granite rock of the Canadian Shield (a stable rock formation) in Northern Canada. In terms of application to the oil sands fields, the nuclear waste issue will be resolved prior to the need to dispose of these wastes from the reactors.

VIII. CONCLUSIONS

The use of nuclear energy to extract oil from oil sands is found to be feasible, practical, and economical. In each of three scenarios analyzed, nuclear energy is significantly less expensive than natural gas. The energy cost comparisons indicate that nuclear energy costs range from 2 to 3 times less expensive than similar natural gas energy. In addition, for a 100,000 barrel per day bitumen or syncrude plant, the nuclear option avoids releasing into the environment 100 megatonnes of CO_2 and numerous other greenhouse gases. If Canada wishes to continue to strive to meet their commitments to the Kyoto Accords, they can not afford such emissions if they intend to continue to develop the huge oil sands resource. Further research needs to be done on the optimization of the nuclear plant designs for mission needs as well as addressing the limitations of piping steam and the restrictions on access to water, both of which are common to all energy options.

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