

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 reactor 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 need for 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: using the reactor to produce only the steam needed for the SAGD process; using the reactor to produce steam as well as electricity for the oil sands facility; and 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. 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 CO₂ per year from being released into the atmosphere.

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Executive Summary

Purpose

This report analyzes 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. Natural gas-fired plants provide the energy for projects today, but concerns are heightening within the industry over increased carbon dioxide emissions, volatile natural gas prices, and depletion of the natural gas reserves. Nuclear power is an emission-free alternative to natural gas, but the key to implementation hinges on whether or not nuclear systems can compete economically with natural gas-fired plants in the oil sands industry.

The Canadian Oil Sands Industry

The oil sands deposits in Canada are a major source of crude oil, but, unlike conventional oil, it is in the form of a heavy oil called bitumen, which is too viscous to pump to the surface and requires lots of energy to upgrade into synthetic crude oil [1]. The two general classes of oil sands recovery are mining and in-situ. In mining, the oil sands ore is recovered above ground by electric or hydraulic shovels and transported by heavy-ton trucks before the bitumen can be extracted. For in-situ methods, most of the bitumen is separated from the oil sands in the deposit by injecting steam into the ground to separate the bitumen from the sand. The bitumen is then pumped to the surface for further processing. Most oil sands operations are performed by mining today, but approximately 80% of the deposits in Canada are too deep for surface mining and can only be recovered by in-situ methods [2].

Integration of Nuclear with Oil Sands Facilities

With the exception of labor costs, the largest expense for both open-pit mining and in-situ projects is the energy demand [3]. Natural gas-fired plants currently provide the energy for both open-pit mining and in-situ projects, but the rising prices of natural gas and increasing concerns over greenhouse gas emissions make nuclear energy an attractive option. Although surface mining is the predominant form of oil sands extraction, its

supply is limited, since most reserves are only obtainable by in-situ methods. The focus of this report is on the SAGD method of in-situ oil extraction, which is judged to be the preferable choice for future operations.

Natural Gas

Natural gas is the primary source of energy used in the oil sands industry for recovery, extraction, upgrading, and other site operations. As the price of natural gas rises, due to a decrease in reserves and an increase in demand from personal and industrial use, the cost effectiveness of oil sands operations decreases. The cost of natural gas has been increasing in the last year, creating an environment in which alternatives to natural gas are being sought. Burning natural gas as fuel releases unwanted CO₂ emissions. Currently, Canada and other countries are working to decrease CO₂ emissions as part of the Kyoto accords. Integration of emissions-free nuclear technology with oil sands operations will remove the dependence of the price of oil from oil sands on the volatile and high price of natural gas and also address the problem of CO₂ emissions.

Energy Requirements

Extraction facilities can be divided into three general categories: those that only require process heat, those that require process heat and electricity, and those that require process heat, electricity, and hydrogen to upgrade the bitumen to syncrude on site. In order to compare the different scenarios, a processing plant capable of producing 100,000 barrels per day of bitumen was assumed as a reference design. 100,000 barrels of bitumen can be upgrading to approximately 87,000 barrels of synthetic crude. The thermal requirements for each scenario are calculated and compared to the available output for several reactor systems.

The first scenario requires only process heat to be produced on-site. Electricity for on-site demands is assumed to be taken from the Alberta electric grid and the bitumen, diluted to enable piping, is sold as diluted bitumen (dilbit) to a processing plant. The energy requirements for this process are relatively straight-forward, as they are derived solely from the thermal requirements of the extraction process. The thermal energy requirements for this scenario range from 820 MWth to 1,264 MWth.

The second scenario requires electricity in addition to process heat. In certain areas of Alberta, the transmission lines are somewhat unreliable. Furthermore, the large energy capabilities of a nuclear reactor enable this addition to be made with only the extra capital cost of the turbine systems. This scenario also produces dilbit that is shipped off site after extraction. The energy requirements for this scenario include approximately 1,200 MWth steam and 250 MWe.

The third and final scenario is a self-contained facility that produces its own electricity and process heat and refines the product on site from bitumen into synthetic crude oil (syncrude). To be completely self-sufficient, the scenario includes the production of hydrogen, an essential component in bitumen refining. Using high temperature steam electrolysis, the facility will produce hydrogen and refine the bitumen. The energy requirements for this scenario include approximately 1,300 MWth steam and 740 MWe.

Nuclear Reactor Design Options

Eleven different reactor systems were considered for this application and only three were down-selected to be appropriate for the mission of providing the energy needs required. These include the ACR-700, a Canadian pressurized online refueling heavy water moderated, light water cooled reactor; the AP600, a Westinghouse pressurized reactor which has been certified by the Nuclear Regulatory Commission; and the Pebble Bed Modular Reactor, a 400 MWth high temperature helium cooled, online refueling gas reactor being developed in South Africa and China, and being considered in the US for the Next Generation Nuclear Power Plant. The most salient characteristics of each reactor include the thermal and electric power outputs, core outlet temperatures, fuel type, and coolant type. An evaluation of design specific characteristics that benefit and impede the oil sands extraction process is used to distinguish reactors.

It should be noted that the Atomic Energy of Canada, Ltd. is now pursuing an 1,100 MWe design based on the ACR-700 technology, and that Westinghouse has a larger version of the AP600 in the AP1000. It is not expected that the larger reactor would change the findings of the study, but gross thermal energy could be available in proportionately higher quantities, which is something that should be considered when a plant is being chosen for a specific site and production facility design.

Economics

The lifetime costs (30 years) of process heat, electricity and hydrogen for use in bitumen upgrading are calculated for natural-gas fired facilities and nuclear generated plants. Nuclear energy is found to be more than two times less expensive than natural gas for producing heat for the steam process. This is primarily due to the high cost of natural gas. Electricity can also be produced at two to three times less than either purchasing power off the grid or producing it by a combined cycle gas plant at the site.

Nuclear-produced hydrogen is cheaper than buying from private suppliers and comparable in price to natural gas-produced hydrogen. Natural gas is not only costlier than nuclear, but also much more volatile due to uncertain natural gas market prices and potential pollution costs in complying with the Kyoto protocol.

Therefore, the economic analysis shows that using nuclear power for producing process heat, electricity and hydrogen is the substantially cheaper alternative to using natural gas for the same purpose and/or buying electricity and hydrogen. Among the nuclear options, the PBMR is the least expensive, however, the ACR-700 and AP600 are just as economically feasible.

Licensing

Before a nuclear facility can be implemented, licensing applications must be filed for review with the Canadian Nuclear Safety Commission (CNSC) to address all safety and security issues. Regulatory activity costs C\$3-5 million/year for each reactor, and it can take around 10 years between the application filing and the start of operations. The ACR-700 is the most easily licensable of the proposed reactor designs, given the CNSC's general familiarity with the CANDU-type designs. While the AP600 is already certified in the United States, it must face licensing in Canada which is not judged to be very difficult, given its license approval in the US. The PBMR faces the most difficult licensing challenge despite its inherent safety since this technology has not yet faced a significant licensing process in the US or in South Africa but a version was licensed in Germany.

Siting

In the siting process, access to transmission lines, limitations of piping steam, water limitations, cumbersome plot shapes, will all pose challenges. The wellpads themselves must be optimally distributed across the field, and the central processing facility must be adequate for the field needs. Implementing the recommended scenarios includes adding a nuclear reactor to the central processing facility. The bitumen-processing buildings, water treatment buildings, and administrative buildings remain the same. For the process heat scenario these changes involve solely the steam generation buildings, moving from a gas fired boiler to a nuclear reactor. However, the alterations are much more extensive for Scenarios 2 and 3, including the addition of turbine systems and an entire upgrading facility to refine the bitumen to the syncrude product. These changes are not taken into account in this study, but will have to be considered in the actual implementation.

Canada's Disposal Plan for Nuclear Waste

Prior to the undertaking of any new nuclear project, the plans for disposal of nuclear waste must be considered. 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 there). 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.

It is important to note that the repository is slated to be finished by 2025, and so nuclear power plants in Alberta would not be burdened with breaking new ground in nuclear waste management.

Nuclear Obstacles

There are several obstacles to implementing nuclear power in oil sands operations. Public perception could offer resistance to the project, but a well-planned education effort should adequately address that issue. Educating the CNSC on the non-native reactor designs could be more costly and could delay construction, because the CNSC is currently unfamiliar with the PBMR and the AP600, and would need to study them carefully in order to issue a license. Lastly, due to the unfamiliarity of nuclear plants by the oil sands industry, it is expected that a nuclear utility will be needed to operate the nuclear plant for the oil sands extraction and refining company.

Conclusion

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 CO₂ 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, the restrictions on access to water.

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Abbreviations and Symbols

ΔT	change in temperature
η	net efficiency
τ	isentropic temperature ratio
AC	alternating current
ACR-1000	Advanced CANDU Reactor 1000 MWe
ACR-700	Advanced CANDU Reactor 700 MWe
AECL	Atomic Energy of Canada Limited
Ag-In-Cd	silver-indium-cadmium alloy
AP1000	Advanced Passive PWR, 1000 MWe
AP600	Advanced Passive PWR, 600 MWe
API	American Petroleum Institute
bbl	barrel(s)
B ₄ C	boron carbide
bcf	billion cubic feet
bcf/d	billion cubic feet per day
bcf/y	billion cubic feet per year
BNES	British Nuclear Energy Society
BNFL	British Nuclear Fuels Limited
BNSF	Burlington Northern Santa Fe
°C	degrees Celsius
C\$	Canadian Dollar(s)
C ₁	cost of the first reactor
C _F	capacity factor
C _N	cost of subsequent reactor
c_p	specific heat capacity
CANDU	CANada Deuterium Uranium, PHWR
CANFLEX	CANDU FLEXible fuelling
CANLUB	Fuel with thin layer of graphite between the fuel, pellet, and the sheath
CBM	Coal Bed Methane Production
CCGT	combined cycle gas turbine
CERI	Canadian Energy Research Institute
CH ₄	methane
CN	Canadian National
CNSC	Canadian Nuclear Safety Commission
CO	carbon monoxide
CO ₂	carbon dioxide
CO ₂ E	carbon dioxide emissions
CP	Canadian Pacific

cp	centipoise
CSA	core structure assembly
CSS	cyclic steam stimulation
CT	Consolidated Tailings
dilbit	DILuted BITumen
DOE	United States Department of Energy
€	Euro(s)
E	energy
ECCS	emergency core cooling system
EOR	enhanced oil recovery
ESP	Early Site Permit
°F	degrees Fahrenheit
F_R	fuel rate
FBTR	Fast Breeder Test Reactor
ft ³	cubic feet
g	gram(s)
gal	gallon(s)
GCFR	Gas Cooled Fast Reactor
GP GC	Grand Prairie Grand Cache
GT-MHR	Gas Turbine - Modular Helium Reactor
h	specific enthalpy
H ₂	hydrogen
H ₂ O	water/steam
H ₂ S	hydrogen sulfide
He	helium
HRSG	Heat Recovery Steam Generator
HTGR	High Temperature Gas Cooled Reactor
HTSE	High Temperature Steam Electrolysis
HVAC	heating, ventilation, and cooling
IAEA	International Atomic Energy Agency
ICAPP	International Congress on Advances in Nuclear Power Plants
IDC	Industrial Development Corporation
INEEL	Idaho National Engineering and Environmental Laboratory
INucE	The Institution of Nuclear Engineers
IPS	inclined plane settlers
IRWST	in-containment refueling water storage tank
kg	kilogram(s)
kJ	kilojoule(s)
km	kilometer(s)
km ²	square kilometer(s)
kW	kilowatt(s)
kWh	kilowatt-hour
LMFBR	Liquid Metal Fast Breeder Reactor
LOCA	loss-of-coolant accident
LWR	Light Water Reactor
LWBR	Light Water Breeder Reactor
M	million
m	meter(s)
\dot{m}	mass flow rate

m ²	square meter(s)
m ³	cubic meter(s)
MACSTOR	dry fuel storage facility, used CANDU fuel storage
Mbbl	thousand barrels
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mcf/y	thousand cubic feet per year
MJ	megajoules
mmbbl	million barrels
mmBtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
mmcf/y	million cubic feet per year
MOX	Mixed OXide
MPa	megapascal
MSBR	Molten Salt Breeder Reactor
MSLB	main steam line break
Mt	megatonne(s)
MW	megawatt(s)
MWe	megawatt electric
MWth	megawatt thermal
N ₂ O	nitrous oxide
N ₂ O ₄	dinitrogen tetroxide
NATO	North Atlantic Treaty Organization
NFI	Nuclear Fuel Industries, Limited (Japan)
NO _x	nitrogen oxides
NPP	nuclear power plant
NPV	net present value
NRC	United States Nuclear Regulatory Commission
NSCA	Nuclear Safety and Control Act
NSSS	nuclear steam supply system
NU	natural uranium
NWR	net work ratio
NYMEX	New York Mercantile EXchange
O ₂	oxygen
O ₃	ozone
O&M	Operating and Maintenance
OECD	Organization for Economic Cooperation and Development
OTSG	Once Through Steam Generator
P	power
PAH	polycyclic aromatic hydrocarbon
PBMR	Pebble Bed Modular Reactor
PHWR	Pressurized Heavy Water Reactor
PHTGR	Prismatic High Temperature Gas Cooled Reactor
ppm	parts per million
PRA	Probabilistic Risk Assessment
PTGR	Pressure Tube Graphite Reactor
PuO ₂	plutonium dioxide
PWR	Pressurized Water Reactor

R&D	research and development
\dot{Q}	heat transfer rate
RBMK	Реактор Болшой Мощности Канальный, a PTGR
RCS	reactor control system
RLMN	RaiLink Mackenzie Northern
RLW	RaiLink Lakeland and Waterways
RPV	Reactor Pressure Vessel
RSS	Reactor Shutdown System
s	specific entropy
SAGD	Steam Assisted Gravity Drainage
SC	reduced sulphur compound
sec	second
SEU	slightly enriched uranium
SG ₁	steam generator for turbine loop
SG ₂	steam generator for SAGD loop
SiC	silicon carbide
SMR	Steam Methane Reforming
SO ₂	sulphur dioxide
SOR	steam-to-oil ratio
SSCR	Spectral Shift Converter Reactor
STP	South Tailing Pond
syncrude	SYNthetic CRUDE
T	temperature
T_E	Thermal energy
THAI	toe-to-heel air injection
ThO ₂	thorium oxide
TRISO	TRI ISOtropic
T-s diagram	temperature-specific entropy diagram
UO ₂	uranium dioxide
UPuC	uranium plutonium carbide
US\$	United States Dollar(s)
USNRC	United States Nuclear Regulatory Commission
VAPEX	VAPor EXtraction
VOC	volatile organic compound
\dot{W}	rate of work
WCSB	Western Canadian Sedimentary Basin
ZEEP	Zero Energy Experimental Pile, prototype CANDU

Chapter 1

Introduction

There has never been a more pressing time to carefully examine future energy options than the present. According to MIT Professor Ernest J. Moniz, former Undersecretary of Energy under the Clinton administration, “Fossil fuels make up eighty-five percent of the world’s present energy use, and developing economies will greatly increase their use of fossil fuels to meet their economic and social goals” [4]. In fact, total world energy consumption is expected to increase nearly fifty-seven percent between 2002 and 2025 [5]. As world energy consumption expands due to population growth and the increasing demands of developing countries, it is apparent that new technologies and applications must be created and applied to the energy industry in order for the world to sustain such growth and development.

Oil, perhaps the most uncertain source of energy, is expected to be consumed at a rate of 103 million barrels per day in 2015, and 119 million barrels per day by 2025 [5]. Sixty percent of the expected increase in oil consumption is due to transportation, a sector in which there are currently few viable alternatives. Although oil is a necessity of the modern world, the largest reserves are located in countries thwarted with much political and social turmoil. The world’s dependency on these countries for oil creates an instability which may have grave consequences.

An alternative to this tenuous dependency is to turn to the ample supply of oil from the Canadian oil sands reserves. The supply of recoverable oil from Canada’s oil sands rivals that of the Middle East. Figure 1.1 compares Canada’s energy potential to that of other major oil-producing countries. The 1.77 billion barrels of recoverable reserves are enough to supply the North American demand for 114 years [6].

Currently, natural gas is the primary source of energy used in the oil sands industry, however, the effectiveness of natural gas in the oil sands industry is questionable. The high demand for natural gas and its substantially depleting reserves in North America

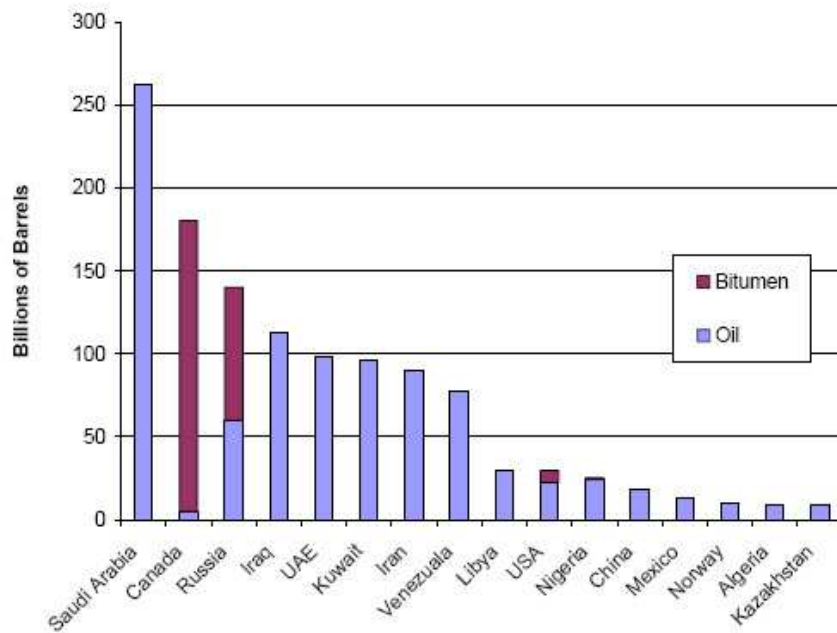


Figure 1.1: Estimated Recoverable Oil and Bitumen Reserves by Country (Adapted:[7])

create a significant instability in the production chain. A limitation 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 countries total emissions under the Kyoto protocol and could prove to be expensive for oil sands development companies. Nuclear energy promises to be an excellent alternative to natural gas energy in order to overcome these limitations.

The mission of the present report is to design an oil sands production facility that uses nuclear energy to provide heat and steam for the purposes of in-situ extraction, electricity, and hydrogen production. Environmental, political, and economic factors will play a crucial role in the actual implementation of a nuclear system, as such these factors are carefully studied. Five major areas are analyzed: extraction process, reactor choice, thermo-hydraulic design, economic analysis, and political evaluation.

This report integrates three different reactors into three oil sands operations. The reactors used are the PBMR, the AP600, and the ACR-700. The configurations are a combination of producing process heat for in-situ extraction, system electricity, and process heat and electricity for hydrogen production. Using these different reactors and configurations, this report compares the economics of using nuclear technology in oil sands with that of natural gas technology. A nuclear power plant used in oil sands production will reduce the world's dependency on oil in unstable countries, reduce global emissions, and ultimately cost consumers and companies less. The applications presented in this report provide an initial step toward realizing these benefits.

Chapter 2

The Canadian Oil Sands Industry

2.1 Introduction

The oil sands deposits in Canada are a vast resource of crude oil, though only recently has the production rivaled that of conventional crude oil. This chapter begins with an overview of oil sands resources in Canada and the planned growth of the industry over the next 15 years. A general description is then given of open-pit mining and in-situ methods of producing oil from the oil sands deposits. Chapter 3 discusses the integration of a nuclear power plant (NPP) with the different production methods presented in this chapter.

2.2 Canadian Resources

Oil sands are a mixture of sand, clay, water and bitumen—a highly viscous heavy oil. The oil sands deposits in Canada are a major source of crude oil, but, unlike conventional oil, the bitumen is too viscous to pump to the surface and has a much higher carbon-to-hydrogen ratio. The higher the carbon-to-hydrogen ratio is, the lower the quality of oil. The oil sands industries face challenges in finding ways to recover the bitumen from the oil sands and also in having to upgrade the bitumen to higher quality oil [1].

The two general classes of oil sands recovery are 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.

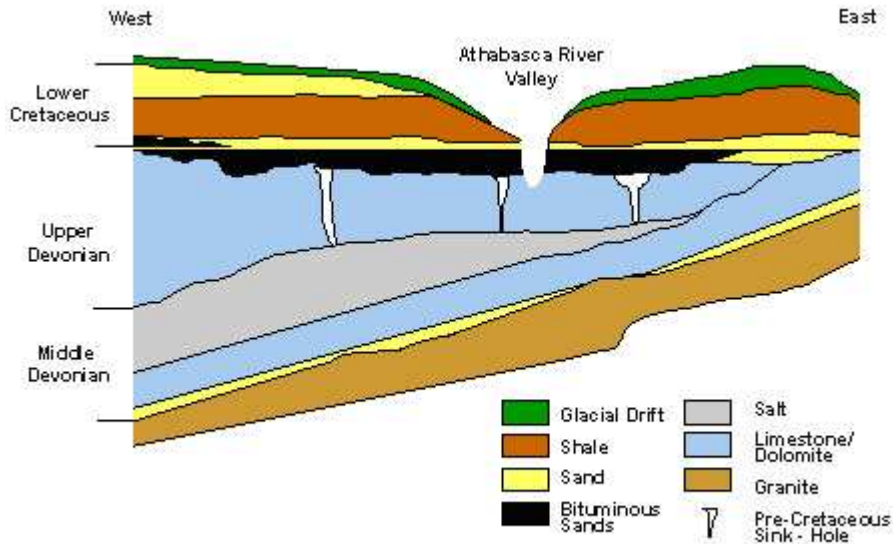


Figure 2.1: Geological Layers in the Athabasca Oil Sands Area (Source: [8])

While both methods are used today, deposits that are greater than 75 meters underground are too deep for surface mining techniques. A simplified geological cross-section of the Athabasca bituminous sands (oil sands) area is shown in Figure 2.1. Given this depth limit, approximately 80% of the deposits in Canada are too deep for surface mining and can only be recovered by in-situ methods [2]. Table 2.1 shows the Canadian bitumen reserves that are surface-mineable and those that are recoverable only by in-situ methods. The initial volume-in-place is the known volume of underground bitumen, based on current data, without taking into consideration any amount that has already been recovered. The initial established reserve volume is the amount of oil available from currently established reserves. The ultimate volume-in-place refers to the volume of underground bitumen expected to be found after all reservoir exploration has ended. The ultimate-recoverable volume is the expected amount of the ultimate volume-in-place that is capable of being recovered [2].

Billion Barrels	Initial Volume in Place	Initial Established Reserve Volume	Ultimate Volume in Place	Ultimate Recoverable Volume
Mineable	110	35	140	70
In-Situ	1,520	143	2,380	250
Total	1,610	178	2,520	320

Table 2.1: Bitumen Resources (Source: [2])

The Canadian oil sands deposits represent as much as one-third of the world's known oil reserves [9]. Nearly all Canadian bitumen is located in the province of Alberta as shown in Figure 2.2. The three main reservoir locations are Athabasca, Cold Lake and Peace River. Together, these areas encompass nearly 60,000 km², which is roughly the

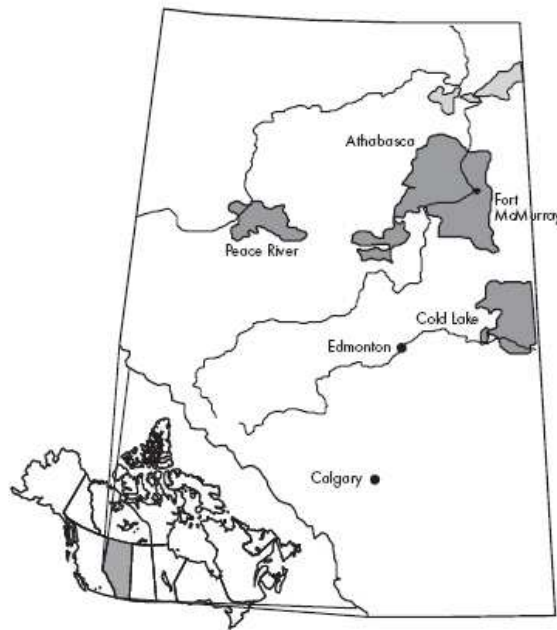


Figure 2.2: Canadian Oil Sands are located in three areas of Alberta: Athabasca, Cold Lake, and Fort McMurray (Source: [2])

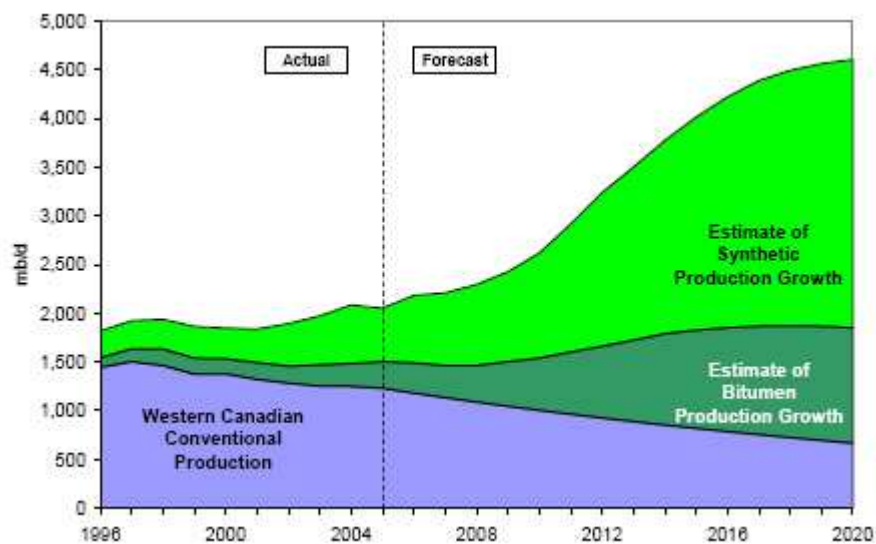


Figure 2.3: Forecast of Oil Sands Production Compared to Conventional Oil Production Adapted from (Adapted: [7])

size of Ireland or Scotland [2]. As shown in Table 2.1, the ultimate recoverable volume of bitumen for these reserves is estimated at around 320 billion barrels. Although this is a small fraction of the total ultimate volume-in-place, the 178 billion barrels of initial established reserves are enough to satisfy the domestic demand for crude oil for over 200 years [2].

Though the bitumen is difficult to recover and requires upgrading, the oil sands industry is becoming an integral part of the world's energy supply as oil prices continue to rise

and the production costs of bitumen continue to fall. This year, oil sands operators are expected to surpass Canada's conventional oil production for the first time, producing more than 1.1 million barrels of oil per day [10]. One report [7] forecasts that oil sands production will makeup 85% of the total western Canadian oil production by 2020, as shown in Figure 2.3.

2.3 Open Pit Mining

Mining operations are limited to areas in the Athabasca region [2]; in the Cold Lake and Peace River regions, however, in-situ methods are needed to recover the oil because the deposits are too deep for mining operations. The area of surface-mineable bitumen in Athabasca spans 3,080 km² [1]. An example of oil sands mining pit showing the extent of the impact on the land is shown in Figure 2.4.



Figure 2.4: Oil Sands Surface Mining Pit (Source: [11])

2.3.1 Recovery

The first step in open-pit mining is to remove the top layer of forest and muskeg. Then, the overburden, which consists of rocks, sand and clay, is taken away to expose the oil sands ore. Most of the overburden is stored in-pit for land reclamation after the oil sands have been mined away, but some of it is needed to construct the containment structures for the tailings ponds. Originally, mining was done through the use of bucketwheel excavators and draglines, but this method was costly and inefficient. As of 2005, bucketwheels and draglines have been phased out. All three Athabasca mining plants now use heavy-hauler trucks and electric or hydraulic shovels to mine the ore. The shovels dig out the ore and

place it into trucks that range from 240-ton to 400-ton capacity. The trucks transport the ore to crushers that break the ore down in preparation for bitumen extraction. The mining is performed 24 hours a day, 365 days a year and the trucks and shovels must be capable of working in extreme climates. For oil sands deposits too shallow for in-situ, no alternatives to surface mining are expected for the next 25 years. [9][12]

2.3.2 Bitumen Extraction

After going through the crushers, the oil sands are sent to an extraction plant whereby the bitumen is separated from the sand and water present in the oil sands. The bitumen extraction steps include conditioning, separation and froth treatment, as outlined in Figure 2.5. The ore is first mined (A), and then sent to crushers (B). The crushed chunks of ore are sent to a rotating drum for conditioning (C). The conditioned slurry of water, sand and bitumen is piped to the separator (D). The bitumen is extracted in the separator and the sand and water are sent to tailings ponds (E). The bitumen leaving the separator is in the form of froth and is sent to a froth treatment plant (F). More detail on the conditioning, separation, and froth treatment steps is given in the three sections that follow.

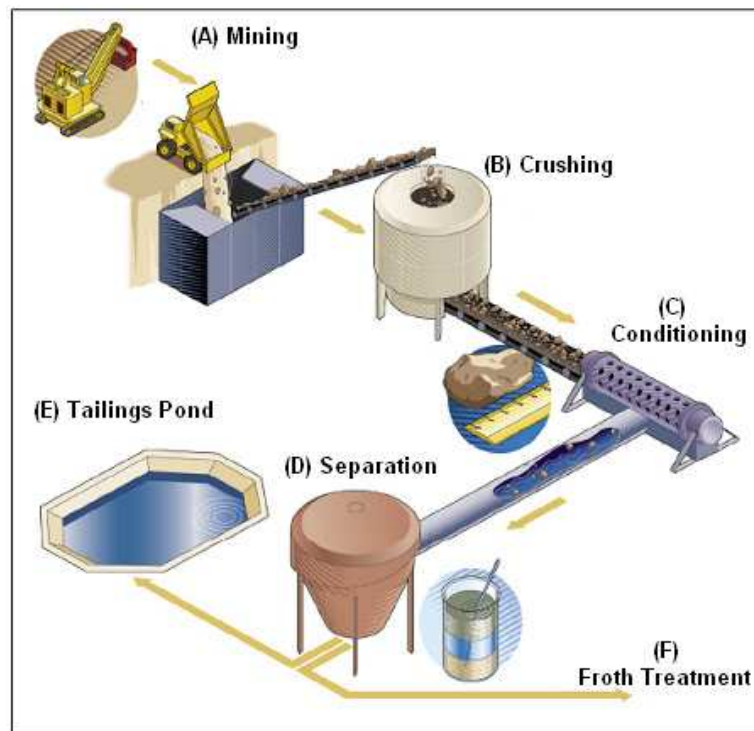


Figure 2.5: Bitumen Extraction of Oil Sands (Adapted from Source: [13])

Conditioning

First, the mined oil sands are sent through crushers that break up the ore into 45 cm chunks [13]. These chunks are sent by conveyer belt to a rotating drum where the oil sands are mixed with hot water to form a slurry before being transported to the separator [9]. A newer approach, called hydrotransplant, does not require conveyer belts or rotating drums. After the oil sand goes through the crusher, it is mixed with warm water and piped straight to the separator (not shown in Figure 2.5) [9].

Separation

The slurry is piped to primary separation vessel where the mixture is separated into a layer of bitumen froth at the top, a layer of sand at the bottom, and a combination of bitumen, sand and water in the middle (called middlings). The slurry is composed of 80% sand, 10–12% bitumen, and 8–10% water. The bitumen froth is skimmed off the top, the sand at the bottom is pumped off into a tailings pond, and the middlings are sent through a secondary separation vessel to retrieve more bitumen. The bitumen froth enters a de-aerator where it is heated up to remove air bubbles that could cause cavitation in the pumps. [9]

Froth Treatment

The bitumen froth at this stage is impure, containing about 30% water and 10% solids by weight. This froth then goes through a treatment plant to remove excess water and solids. To make the bitumen froth flow more easily during this stage, it is mixed with a type of liquid diluent, usually naphtha. The diluted bitumen froth passes over inclined plane settlers (IPS), causing the heavier solid particles in the froth to settle by gravity. Centrifuges are then used to further separate water and solids from the bitumen. After froth treatment, the end product is diluted bitumen. [9]

2.4 In-situ Methods

2.4.1 Cyclic Steam Stimulation (CSS)

Cyclic steam stimulation (CSS), also referred to as “steam soak” or “huff and puff”, is a three-stage process that uses a single well that can either be vertical or horizontal. First, steam is injected into the well at rates of around 1000 Bbl/day [1]. Then, the well is

closed to allow the steam to soak into the surrounding bitumen. This steam lowers the viscosity of the bitumen, allowing it to separate from the sand and mobilize toward the well. In the final stage, the mixture of condensed steam and bitumen, called an emulsion, is pumped out and fed into a nearby facility for processing. These steps compose one cycle; the cycle is then repeated until the steam to oil ratios become so low that the process is uneconomical. CSS can only recover between 20–25% of the oil in place, which is lower than both steam assisted gravity drainage and open-pit mining [2]. The stages of the process are shown in Figure 2.6.

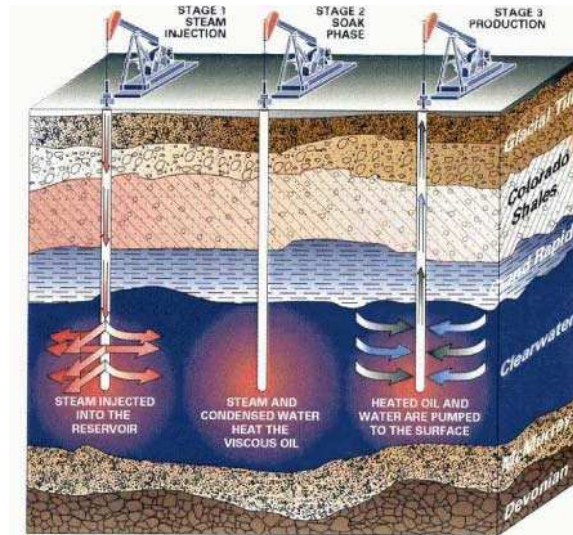


Figure 2.6: Stages of Cyclic Steam Stimulation (Source: [14])

2.4.2 Steam Assisted Gravity Drainage (SAGD)

Steam assisted gravity drainage (SAGD) is described in detail in Section D; however, an overview is provided here as well. In SAGD, steam is continuously injected into the ground, causing the condensate and bitumen to flow to a production well by gravity [1]. Two horizontal wells are drilled into the underground oil sands deposits as shown in Figure 2.7. 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 [15]. 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 [3]. 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. 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,

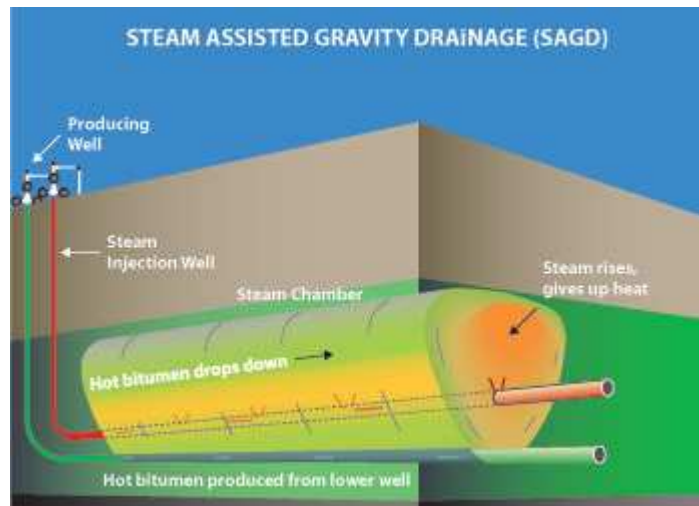


Figure 2.7: Model of SAGD wells placed underground (Source: [16])

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 [1].

2.4.3 In-situ Processing Facility

The bitumen processing facility for in-situ extraction is also described in detail in Appendix D, but a brief overview is provided here. The produced emulsion that comes out of the CSS and SAGD production wells consists mostly of bitumen, water, and vapors. Some sand is present, but most is left in the reservoir. The role of the processing facility is to process this emulsion into a final product of diluted bitumen. The vapors, most of the remaining sand, and much of the water are first separated from the bitumen. Some type of diluent is mixed with the bitumen, which helps in the separation of remaining water from the bitumen. After this separation is performed, more diluent is added to the bitumen, and a final treatment is performed to remove as much of any water and sand that are still present as is possible. The end product is diluted bitumen (dilbit). [15] [17]

2.4.4 Other In-Situ Technologies

Other in-situ technologies such as cold production, toe-to-heel air injection (THAI) and vapor extraction (VAPEX) are known, but less detail is provided because these methods are not considered for integration with a NPP, as described in Section 3.2. Cold production is a method that does not require thermal stimulation to mobilize the bitumen. This method only applies to certain areas in Athabasca (Wabasca) and substantial growth is not expected [2]. A few pilot projects have started up with the experimental technologies such as THAI and VAPEX. THAI is a method of combusting the oil sands underground

to heat up and mobilize the bitumen toward production wells. VAPEX is similar to SAGD, but organic gases are pumped into the ground to extract the bitumen instead of steam. Both THAI and VAPEX methods claim to offer benefits over current methods of in-situ extraction; however, both methods are still in testing and surface mining and SAGD are expected to be the dominant recovery methods until at least 2015 [2].

2.5 Bitumen Upgrading

The final product that is produced by the various bitumen extraction and processing methods that have been described is diluted bitumen, or dilbit. Dilbit must be upgraded 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 was extracted. Section D.2 describes in detail both the transport of dilbit and the on-site upgrading of dilbit.

In summary, the on-site upgrading process consists of three major components: naphtha removal, coking, and hydrotreating. In naphtha removal, the naphtha (a type of diluent) is removed from the dilbit, so that only the bitumen remains. Coking involves separating out the heaviest hydrocarbon molecules from the bitumen in order to decrease its average molecular weight, which increases the quality of the material. Finally, hydrotreating involves exposing the bitumen to hydrogen at high pressures, which further increases the quality of the material. Chapter 4 describes the energy and hydrogen requirements of on-site upgrading.

2.6 Environmental Concerns

2.6.1 Water

Large quantities of water are needed to produce steam and hot water for both mining and in-situ projects. Even though water is recycled for both projects, the recycled water is often not processed quickly enough, so makeup water is necessary. For the Athabasca region, the Athabasca River provides this water, but there are limits imposed on the rate of water removal. The maximum allowable water removal rate is $14.2 \text{ m}^3/\text{sec}$ and 450 million m^3/year [6]. The Athabasca River flow rate varies seasonally; at some moments during the year, the flow rate is lower than the necessary amount of water needed for the oil sands processing plants [6]. Not only that, but the minerals and salts present in the water need to be removed for the steam generators that require pure water. More

information on how the concerns with water management factor in for the integration of a NPP with the oil sands facilities is given in Section 8.1.8.

2.6.2 Tailings ponds

The current methods of surface-mining result in the accumulation of large volumes of fluid wastes called tailings. These tailings are made up of water, clay, sand, and residual bitumen. After bitumen extraction, these tailings must be stored in large dammed reservoirs called “tailing ponds” until they can be reclaimed or used to fill the mined-out pits. An example of a tailings pond is the South Tailings Pond (STP) currently under construction at the Millennium Mine site operated by Suncor Energy Inc. This plant will have a maximum storage capacity of 350 million m³ and total footprint of 23 km² [18].

Because of the tailings’ extremely low rate of consolidation, the tailings ponds must be constructed to last for the lifetime of the plant and must be guarded against erosion, breaching, and “foundation creep” [2]. To create these structures, the overburden layer removed in the mining process is used to build the outer dykes. The “tailings sand dyke” is constructed on top of this overburden dyke over time, and the interior of this structure functions as a tailings receptacle during its operational life [2]. The entire structure can reach the height of over 100 m above the surface level [19]. The prevention of seepage of pollutants from these ponds into freshwater aquifers is an ongoing environmental concern despite technological advances.

The fine clay/water mixture forms a stable suspension as the heavier tailings sands fall to the bottom of the pond. In time, these fine clay particles settle to form a fluid-like deposit called fine tailings. Some companies, including Suncor Energy Inc., use Consolidated Tailings (CT) technology to eliminate the large fluid volumes created by the tailings ponds. Through the use of gypsum, a byproduct of the flue gas desulphurization plant, the tailings are processed into solid material capable of supporting vegetation and wildlife within 20 years [18]. Without the use of this technology, the fine tailings would not consolidate into a soil-like deposit for hundreds of years.

For the in-situ methods, disposal sites are required for the sand that is separated out during the processing of the bitumen. Since most of the bitumen is left in the deposit for in-situ methods, the size of the disposal sites are much smaller than the size of tailings ponds for mining projects and are much less of an environmental concern.

2.6.3 Land reclamation

Once reserves of a particular deposit in Canada have been exhausted or processing activities have been permanently suspended, companies are required by law to decommission sites to include building waste-rock and tailings management facilities and reclaiming those areas affected by their activities to the satisfaction of provincial and federal regulatory authorities [20]. The land can be reclaimed as a forest, grassland or wetland, but must have a “productive capability at least equal to its condition before operations” [2]. This is done by replacing sand, soil and muskeg so that the area can be returned to a productive state. Once the soil has been replaced, the area is reforested with trees, grasses, and shrubs.

This re-establishment of self-sustaining ecosystems is a major challenge because of the large disturbance of the land. In open-pit mining, the land is cleared, surface strata and soil are disturbed, and fish and wildlife populations are affected. The current method of reclamation involves leaving large areas of land in a disturbed state for many years while natural processes work to re-establish the landscape [2]. Once the soil is reconstructed, trees and shrubs are planted, and grasses are sown to prepare the land for future use. As an example, Syncrude spends more than 10 million dollars annually on land reclamation, and in February 1993, they went as far as to move a herd of wood bison to reclaimed land [21]. Suncor Energy Inc. has also worked hard to reclaim land, with almost 9% of their disturbed land already reclaimed [2]. Though this method works to a certain degree, the ultimate goal is to minimize the disturbance area to prevent the destruction of large areas of land.

A benefit of the in-situ recovery method is the reduced surface area disturbed by the process. Because very little surface soil is removed compared to open-pit mining methods, the forests, fish, and wildlife are largely unaffected.

Chapter 3

Integration of Nuclear with Oil Sands Facilities

With the exception of labor costs, the largest expense for both open-pit mining and in-situ projects is the energy demand [3]. Natural gas-fired plants currently provide the energy for both open-pit mining and in-situ projects. The projects use the energy to produce electricity, high-pressure steam and hot water for operations [3], but the rising prices of natural gas and increasing concerns over greenhouse gas emissions are spurring the investigation of alternatives that are more economical and environmentally acceptable. Nuclear energy has emerged as an attractive option. With no direct CO₂ emissions, it is ozone-friendly, and a recent study [3] has shown that nuclear is competitive with natural gas in providing the energy needs of oil sands projects (more on natural gas in Chapter 4). The increasing oil production rates in the Athabasca region strengthen the feasibility of using nuclear power plants to meet the energy needs [3].

3.1 Open-pit Mining vs. In-situ

This section compares the methods of open-pit mining and in-situ extraction, with an emphasis on the varying applications, strengths, and weaknesses of each, especially as they relate to the use of a nuclear energy supply.

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. An advantage that mining has over in-situ is that mining projects are already established with production rates exceeding 100,000 bbl/day, and the power output of nuclear power plants is best suited for the energy needs of facilities with large production rates. Most in-situ projects range from 5,000 bbl/day to

30,000 bbl/day; however, the projects are designed to be built in phases and some aim to produce more than 100,000 bbl/day in the next five years [7]. The phased construction of in-situ projects can be a serious advantage from a business perspective. It capacitates incremental capital expenditures with concurrently increasing plant productivity to immediately offset the cost of the investment.

A major disadvantage of in-situ projects over mining projects is that steam is piped much longer distances. Steam is difficult to pipe long distances because high temperatures and pressures are needed in order for it to remain a vapor. In mining projects, the components that require steam are located in close proximity to each other. For the Horizon proposed mining project, which plans to produce over 100,000 bbl/day by 2009 [7], steam will be piped no further than 2000 m [22]. In-situ projects, however, require the steam to be piped much further distances. For the Jackfish proposed in-situ project, which plans to produce 35,000 bbl/day by 2008 [7], steam needs to be piped to well pads that are sometimes 5000 m from the steam generators [15]. Future in-situ operations aim to produce over 100,000 bbl/day, but more well heads will need to be used, and piping distances will likely exceed 5000 m for some of the well pads. The limit on the radial distance for piping steam is around 15 km [23].

Due to the long payoff period of the capital investment, the lifetime of the production field is an important indicator of the economic feasibility of a project. Surface mining projects typically have a lifetime of 30 years [23], while in-situ operations have lifetimes in the upper limit of 25 years, though most have lifetimes between 10–15 years [23]. Companies have as of yet been unable to resolve this difficulty, so the companies that are considering integration with a NPP in the near future are primarily mining projects [23]. However, there are a number of creative in-situ configurations that favor the investigation of nuclear power that will be presented later in this study.

Despite its disadvantages, in-situ production is expected to play a dominant role in the long-term future of the oil sands industry [12] since 80% of the oil sands in Canada are too deep to be recovered by mining methods. Mining projects will be the main oil sands industry for the next 10-15 years, but the production rate of surface mining projects is expected to plateau around 2020 [12]. The exact production rate for in-situ operations is more difficult to predict, since in-situ methods have not been attempted on a large scale and the growth of new in-situ technologies is unknown. Three forecasts are given in Figure 3.1 that show how in-situ production will compare to that of mining. Figure 3.1 predicts that by 2020, in-situ production will represent between 27% and 45% of total oil sands production in Canada, and by 2030, it will represent from 33% to upwards of 50%.

It is important to mention the environmental impact of mining projects vs. in-situ projects. Open-pit mining projects cause much more disturbance to the land than in-situ

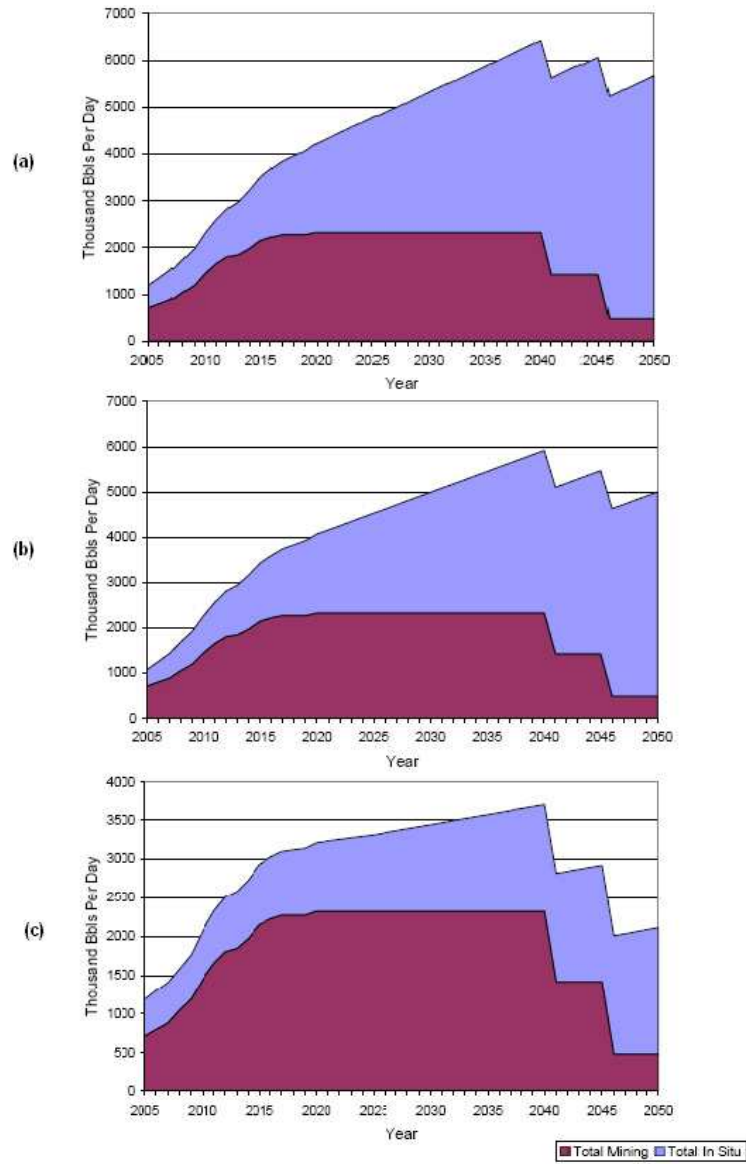


Figure 3.1: Three forecasts of in-situ production compared to mining production (Adapted : [12])

projects. The process of stripping the top layer of overburden away in mining projects has much more impact than any disturbance caused by in-situ projects. Environmental effects are described in more detail in Section 2.6.3. In-situ projects, on the other hand, consume much more natural gas than mining projects. On average, mining projects consume 0.60 mcf of natural gas per barrel of syncrude while in-situ projects consume 1.15 mcf per barrel of syncrude [7] (more on natural gas in Chapter 4). Despite this difference, the steam-to-oil ratio for both mining and SAGD is about the same. Overall, the environmental impact of surface mining projects is greater than that of in-situ projects.

The following is a summary of the comparison between integrating a NPP with mining projects and with in-situ projects:

Pros of Open-pit Mining

- High established production rates are well suited for large energy output of nuclear reactor
- Limitations on piping steam are not much of a problem
- A field lifetime of about 30 years is cost-effective for reactors

Cons of Open-pit Mining

- Mining projects will be main producers of oil from oil sands in Canada, but production will level off around 2020
- Environmental impact of mining facilities is higher

Pros of In-situ

- Projects are designed to be built in phases that allow for incrementally higher production rates
- Planned projects aim to produce over 100,000 bbl/day
- In-situ projects are expected to play a dominant role in the long-term future of the oil sands industry
- Environmental impact of in-situ facilities is lower

Cons of In-situ

- Largest in-situ projects today only produce around 35,000 bbl/day and have not been established on a large scale
- Limitations on piping steam are a problem
- Very rich fields have well lifetimes of around 25 years, but most well lifetimes are around 10-15 years

The integration with mining projects is a viable route to take that is being explored seriously by some members of industry, but the focus of this project is on the more innovative integration with in-situ projects.

3.2 SAGD vs. CSS

A general analysis of integration of a NPP with in-situ methods was given above, but this section analyzes which of the in-situ methods is better suited for integration with a NPP. The comparison focuses on the two most common in-situ methods, SAGD and CSS; the integration of a NPP with any other in-situ technologies was ruled out. Cold production only applies to certain areas in Athabasca (Wabasca) and substantial growth is not expected [2]. Since nuclear plants are more suited for projects with larger production capacities as well as projects with a potential for future growth, the integration of a NPP with cold production was not considered. The integration of a NPP with either THAI or VAPEX was also not considered since both methods are still in testing.

Table 3.1 outlines some of the advantages and disadvantages of SAGD and CSS. The main drawback of CSS is its inefficiency. The recovery rate of bitumen-in-place for SAGD is between 40–60%, while the recovery rate for CSS is between 20–25% [2]. Also, SAGD requires less steam than CSS per barrel of oil: the steam-to-oil-ratio (SOR) for SAGD ranges from 2.5–3 and that for CSS ranges from 3–4, or even worse [12]. One Athabasca project reported a prohibitively low SOR of 7 [15]. Though CSS projects in Cold Lake have proven to be economically viable, those in Athabasca have not, and the majority of new in-situ projects plan to use SAGD. The most relevant drawback of CSS for use with nuclear power is its operating schedule. On average, the steam is needed for two weeks every few months. It would be highly inefficient to shut the reactor down and then power back up again for the relevant portions of the process. In order to have the reactor continuously running, the steam would have to be fed into a different well every two weeks so that each well would be at a different stage in the cycle. On the other hand, since CSS only requires one well, the capital cost is typically less than that for SAGD. The increased profit associated with the high recovery rate of SAGD, however, outweighs this higher capital cost. As for the natural gas demands for each method, both are comparable at 1.0 mcf per barrel of production for CSS and 1.2 mcf per barrel of production for SAGD [2]. The above arguments make it clear that SAGD is the preferred recovery method for use with nuclear power in the oil sands industry.

Characteristic	SAGD	CSS
Higher recovery rate	X	
Lower steam-to-oil ratio	X	
Greater number of future projects	X	
Continuous steam injection	X	
Lower capital cost		X
Less energy required per barrel of bitumen	X	

Table 3.1: Advantages and Disadvantages of SAGD and CSS In-situ Technologies

Chapter 4

Natural Gas

4.1 Natural Gas Overview

Large amounts of natural gas, electricity, transportation fuels, and hydrogen are consumed in the process of recovering and upgrading bitumen from oil sands [24]. 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. Operation of mine machinery, in-situ well pumps, and other project energy needs use the electricity that is produced, with any excess electricity supplied to the grid [25].

Oil sands projects fuel their on-site electricity generators with externally sourced natural gas. Natural gas fired turbines generate electricity to operate equipment and facilities, provide heat that is used to generate steam, and provide process heat for bitumen recovery, extraction, and upgrading. Hydro-cracking and hydro-treating use hydrogen from natural gas to upgrade the bitumen to synthetic crude oil [24]. Figure 4.1 illustrates these uses for natural gas in oil sands facilities.

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, so the gas price has continued to rise. At this pace, oil sands projects will not be able to sustain their dependence on it [24].

The economic advantage of using natural gas cogeneration plants to heat steam for in-situ extraction methods was apparent initially, when natural gas was seemingly cheap and abundant. As the oil-sands production industry becomes more heavily reliant on it, it has now become apparent that the costs and supply of natural gas may force the

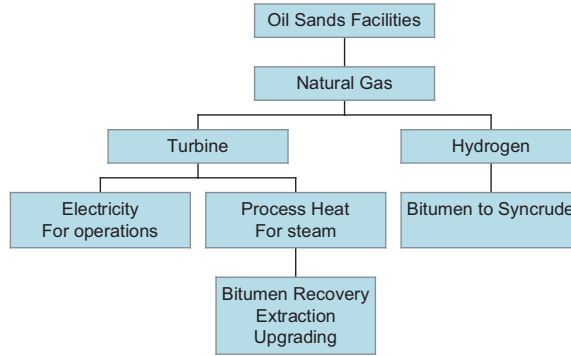


Figure 4.1: Natural Gas Uses in Oil Sands Facilities

industry to consider a more economically viable option.

This section aims to demonstrate that as the supply of natural gas decreases and the demand for natural gas increases, thus causing an increase in the price of natural gas, oil sands projects will need to look to alternative methods in order to sustain the productivity and economic viability of their operations. First, we will outline the technical requirements for the production of steam, electricity, and hydrogen using natural gas. Next, we will discuss the current natural gas needs in the oil sands industry and then the decreasing supply of natural gas. Finally, we will conclude with the environmental concerns related to oil sands operations fueled by natural gas.

4.2 Natural Gas Situation

4.2.1 Demand for Natural Gas

About 30% of total primary energy consumption in Canada was supplied by natural gas in 2003. During the same year, the primary consumption in Canada was 3,085 bcf (billion cubic feet) and 22,219 bcf in the United States [26]. One bcf of natural gas can supply the energy needs of over 11,000 homes or 2,000 commercial entities or 90 industrial concerns for one year. Figure 4.2 shows the distribution of natural gas use in Canada, with 44% exported to the US. Natural gas demand for power generation in North America has had the strongest growth, at an annual rate of 4.9% between 1990 and 2001. From 2002 to 2020, the demand for natural gas is estimated to grow about 1.9% a year. North America will have to rely on new sources of natural gas to fulfill the increasing demand, or the price of natural gas will increase [27]. Figure 4.3 shows the supply and demand forecasts for North America [27].

The natural gas demand is expected to increase with little potential to increase the natural

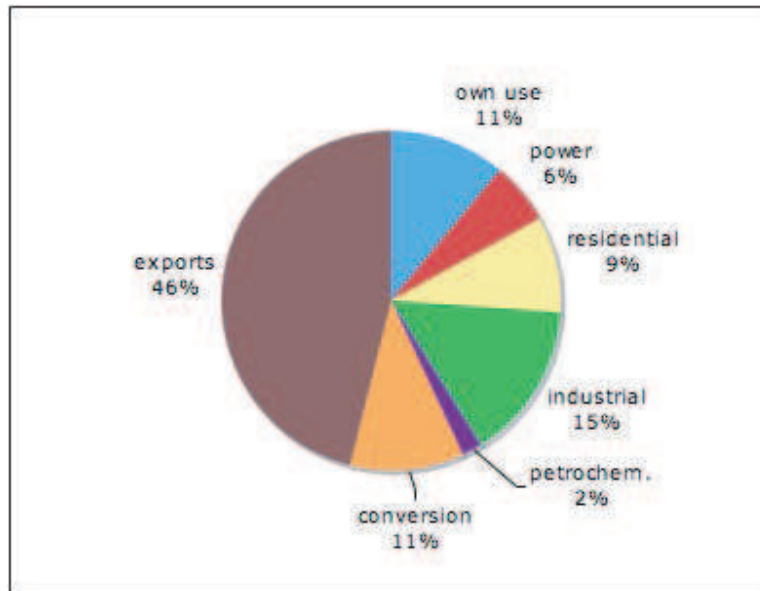


Figure 4.2: Canadian Use of Natural Gas (Source: [27])

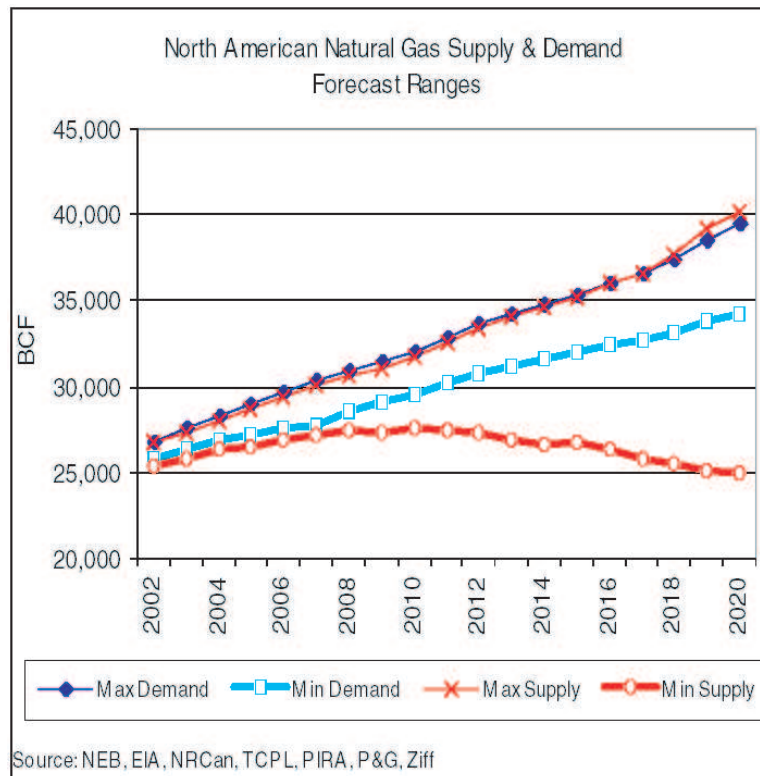


Figure 4.3: North American Natural Gas Supply and Demand (Source: [27])

gas supply. These factors will cause the price of this commodity to increase unless a new supply is discovered or reduced consumption occurs. Additional supply may include frontier and unconventional sources, such as coal bed methane, of natural gas [28]. For more on the Canadian supply of natural gas and frontier and unconventional sources of natural gas see Appendix C.

4.2.2 Natural gas cost

The natural gas market over the past ten years is characterized by its volatile price and increasingly tightened supply and demand chain. Figure 4.4 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 US\$10.00/mmBtu.



Figure 4.4: Historical Trend of Natural Gas Prices (Source: [29])

The demand for oil has been steadily increasing, not only in North America, but also throughout the world. 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. It is highly unlikely that the current rate of natural gas production will grow at a rate anywhere close to the growth in demand. The ultimate result will be increasingly volatile gas prices, rising at a rapid pace to satisfy market equilibrium.

4.3 Natural Gas Demands in the Oil Sands Industry

The Alberta Chamber of Resources estimated the average natural gas demands for oil sands operations, based on contributions from commercial oil sands operations such as Syncor and Syncrude [25]. According to the National Energy Board, Alberta oil sands industry may use up to 60% of the natural gas production of the MacKenzie Valley, coal bed methane, and WCSB combined, by 2030 [24].

Forecasts for the natural gas demands of oil sands include the current needs and needs for the future. An increase in hydrogen supply will be needed for the demand of higher

In-Situ Recovery	Mining Recovery	Hydrogen for Upgrading	Fuel for Upgrading
1000	250	400	80

Table 4.1: Consumption of Natural Gas (in standard cubic feet) per Barrel of Bitumen (Source: [25])

quality synthetic crude oil. Alternatively, technological advances could make processing more efficient and thus decrease the need for hydrogen. Assuming these two trends, the demand for natural gas per barrel of synthetic crude oil will remain constant.

Natural gas is used in integrating mining projects to produce process heat, electricity, and as a source of hydrogen for upgrading (hydrotreating). Electricity is needed for the electric shovels and the crusher [25]. Operation of the hydrotransport pipelines and facilities that move the oil sands in a water-based slurry to the bitumen extraction sites also uses energy. Natural gas is also used as a source of heat for the hot water extraction of bitumen [24]. For in-situ projects, natural gas is used to produce electricity to power the pumps. Natural gas also produces process heat for steam production. Table 4.1 shows the estimated natural gas demands per barrel of bitumen [25].

The amount of natural gas used per barrel of bitumen produced for CSS is approximately the same for SAGD at 1.0 to 1.2 mcf. Mining recovery alone uses 250 cubic feet of natural gas per barrel of bitumen [24]. Currently, natural gas demand is about 400 cubic feet per barrel to produce hydrogen for the upgrading of bitumen to syncrude. Utilizing coke burning decreases the natural gas demand by 80 cubic feet per barrel of upgraded fuel [25]. For upgrading alone, about 500 cubic feet of natural gas is needed per barrel of synthetic crude oil. Figure 4.5 shows the natural gas demands for different oil sands plants processing 100,000 bbl/day.

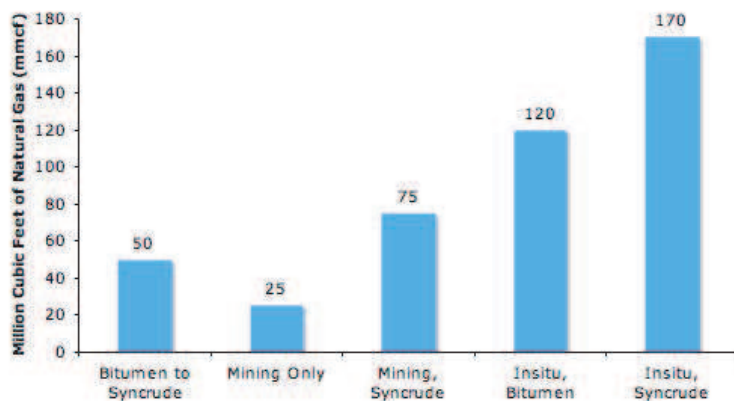


Figure 4.5: Maximum Natural Gas Demands for Different Oil Sands Operations, Processing 100,000 bbl/day

4.3.1 Alternatives to Natural Gas as an Energy Source

As the supply of natural gas decreases, the oil sands industry is looking into internal or external resources to be used for energy and hydrogen. Besides producing hydrogen, gasification of residues produces process heat and electricity as co-products. This process would use the residues from the bitumen barrel for fuel, power, and hydrogen. To completely replace natural gas, about 17% of production is needed for in-situ and about 4% for mining. However, gasification is not as financially efficient at this time as combustion of natural gas [25].

Coal combustion is another option for replacing natural gas. Cogeneration of energy and power using coal is thoroughly researched. Coal is inexpensive and there is an abundant supply in Alberta, but coal combustion would increase greenhouse gas emissions immensely [25].

Nuclear energy is a promising solution to the natural gas crisis. For a SAGD plant producing 150,000 barrels per day, using nuclear technology to produce steam and electricity is currently cost competitive with natural gas at a price of US\$4.25 per mmBtu. As the cost of natural gas increases, nuclear will become a more appealing solution [25].

4.3.2 Alternatives to Natural Gas as a Hydrogen Source

Gasification is the process of converting a solid, such as coal, into a gas for fuel. Gasification of coal, coke, or oil sands residues is used to generate hydrogen. Gasification also produces process heat and electricity. About 10% by weight of original oil sands production needs could be gasified to produce enough hydrogen to upgrade the remaining 90% to high quality synthetic crude oil. Although partial oxidation/gasification uses oxygen, has a lower efficiency, is more expensive, and is a more complicated process for purification of hydrogen, it proves a promising alternative to natural gas [25].

Another alternative method for producing hydrogen without natural gas is electrolysis. This technology has not yet been implemented because of the high cost of the electricity needed. Currently, electrolysis is about three times more expensive than traditional methods used to produce hydrogen, like steam methane reforming (SMR) or residue gasification. Electrolysis is about 65% efficient so the cost is US\$21.37/mmBtu of hydrogen (\sim US\$14/mmBtu for 100% efficiency using 278 kWh of electricity). These numbers compare to US\$7/mmBtu for steam methane reforming [25].

4.3.3 Current Projects with Natural Gas Alternatives

Suncor’s Firebag SAGD project has a cogeneration plant that uses both diesel and natural gas to fuel its steam generators, depending on the cheaper market option. The Nexen/OPTI Long Lake SAGD project will use gasification of the low value, heaviest portion of the bitumen to produce synthetic gas fuel and hydrogen, almost eliminating the need for natural gas [24].

4.4 Technical Analysis of Natural Gas Usage

Given the uncertain nature of the natural gas market, it is helpful to look at the specific natural gas consumption of the design basis plant for this report for further economic analysis. Chapter 5 of this report includes detailed calculations of the energy requirements of a SAGD oil sands facility producing 100,000 Bbl/day. These energy requirements are calculated for three different scenarios. The first scenario uses a plant that only produces process heat for steam production on a SAGD project. Scenario two uses energy for the adequate production of both steam and electricity to run the oil sands facility. Scenario 3 includes the energy requirements for the production of steam, electricity, and hydrogen for the upgrading of bitumen to syncrude.

The calculations of natural gas for a 100,000 Bbl/day facility assume the highest efficiency of a cogeneration plant. Cogeneration plant efficiencies are used in the following calculations because they are much higher than any other cycle currently used, with thermal efficiencies ranging from 50% to 60%.

The calculations below also use the net or lower heating value of natural gas as 33.86 MJ/m³ [1]. The lower heating value was used because it does not include the heat of vaporization of water. The heat of vaporization is not useful because it does not directly influence the amount of steam produced in relation to natural gas consumed.

4.4.1 Production of Steam

From Section 5.2.1, the rate of energy required for the production of steam in the first scenario is between 820 and 1,260 MWth. The daily volume of natural gas required to produce this process heat is calculated using the most conservative (highest) amount of power needed, 1,260 MJ/sec.

$$1,260 \frac{\text{MJ}}{\text{sec}} \times \left(\frac{\text{m}^3}{33.86 \text{ MJ}} \right) \times \left(\frac{31.31 \text{ ft}^3}{\text{m}^3} \right) \times \left(84,600 \frac{\text{sec}}{\text{day}} \right) \approx 98.57 \frac{\text{mcf}}{\text{day}} \quad (4.1)$$

The heating value is multiplied by the power value because it converts each unit of energy into the necessary volume of natural gas needed to produce that energy. The volume is then converted into cubic feet which is the most common unit used in the measurement of natural gas. Finally, the rate is converted into a daily value and the result is the daily amount of natural gas needed to obtain 1,260 MWth of power using natural gas as a heating source.

4.4.2 Production of Electricity

From Section 5.3.1, an additional 250 MWe is needed for the production of electricity. The electricity needed must be converted into the appropriate MWth value using the conservative thermal plant efficiency (60%) of a natural gas plant, explained at the beginning of Section 4.4.

$$\left(\frac{250 \text{ MWe}}{0.6}\right) = 416.67 \text{ MWth} \quad (4.2)$$

This is added to the amount MWth value needed to produce process heat. The total heat required then becomes:

$$(416.67 + 1,260)\text{MWth} = 1,676.67 \text{ MWth} \quad (4.3)$$

The conversions used in Scenario 2 are the same as in Scenario 1:

$$1667.67 \frac{\text{MJ}}{\text{sec}} \times \left(\frac{\text{m}^3}{33.86 \text{ MJ}}\right) \times \left(\frac{31.31 \text{ ft}^3}{\text{m}^3}\right) \times \left(84,600 \frac{\text{sec}}{\text{day}}\right) \approx 131.16 \frac{\text{mcf}}{\text{day}} \quad (4.4)$$

4.4.3 Production of Hydrogen

An additional 310 MWe and 80 MWth is needed for the production of hydrogen. The electricity needs are converted in the same manner as in Section 4.4.2 and then added to the values for the thermal needs for process heat. The resultant value is 2,273.33 MWth:

$$\left(\frac{(250 + 310)\text{MWe}}{0.6}\right) = 933.33 \text{ MWth} \quad (4.5)$$

Total heat required then becomes:

$$(933.33 + 1,260)\text{MWth} = 2,273.33 \text{ MWth} \quad (4.6)$$

The natural gas conversions are calculated in the same manner as in Scenario 1:

$$2,273.33 \frac{\text{MJ}}{\text{sec}} \times \left(\frac{\text{m}^3}{33.86 \text{ MJ}} \right) \times \left(\frac{31.31 \text{ ft}^3}{\text{m}^3} \right) \times \left(84,600 \frac{\text{sec}}{\text{day}} \right) \approx 177.84 \frac{\text{mcf}}{\text{day}} \quad (4.7)$$

The calculations above show the natural gas needs for a 100,000 Bbl/day plant. These needs are quite high, and will increase as the industry continues to grow. The needs are summarized in Table 4.2.

Steam	Electricity	Hydrogen for Upgrading
98.57	131.16	177.84

Table 4.2: Use of Natural Gas (mcf) for 100,000 Bbl/day Plant

4.5 Environmental Analysis

The entire process of extracting bitumen from oil sands regions creates many environmental disturbances which must be taken into consideration, including water use, soil and groundwater contamination, noise from trucks, destruction of plant and animal life, and disturbances of aboriginal people and historical resources, which are discussed in Chapter 2. The largest and most complicated environmental issue associated with the use of natural gas, however, is the emission of greenhouse gases and other air pollutants. These emissions are subject to constantly changing regulations and efforts to control them can prove costly.

4.5.1 Emissions from Oil Sands

Perhaps the largest environmental issue in the oil sands industry is the emission of greenhouse gases, including CO₂, CH₄, and N₂O. In-situ oil sand extraction plants using natural gas as fuel also emit NO_x, VOCs, H₂S, CO, O₃, PAH, SO₂, and SCs, all of which are non-greenhouse gases, in addition to particulate matter and other trace air compounds [12].

Greenhouse gases contribute to global warming by trapping heat from the sun inside the earth's atmosphere. Although CH₄ and N₂O effect global climate change more, oil sands operations do not release nearly as much of these as CO₂, and thus CO₂ takes the focus of emissions reductions efforts in the oil sands industry. The amount of the three greenhouse gases added together (each weighted for its affect on climate change) is

Company	CO ₂ emissions 1990 (tonnes)	CO ₂ Emissions 2000 (tonnes)	Projected CO ₂ emissions 2012 (tonnes)
Syncrude [30]	7,700,000	8,550,000	16,000,000
Suncor [31]	3,663,000	5,344,000	10,696,000
Shell Canada		7,966,000	

Table 4.3: Annual CO₂ emissions from selected oil sands operations that use natural gas.

referred to as the CO₂ equivalent, or CO₂E, and this measurement is most often used to describe greenhouse gas emissions.

Canada’s export-led industry expansion is a substantial source of greenhouse gases. Table 4.3 shows some data on annual CO₂ emissions (the largest and well-documented of the greenhouse gasses) of various oil sand projects using natural gas that are already in operation, to illustrate the typical magnitude of emissions. CO₂ emissions were found by multiplying the CO₂ “intensity” of the company’s operations (tonnes of CO₂ per barrel) in a particular year by the company’s reported or predicted output (in barrels) for that year. It should be noted that each company has been and is planning to reduce the ratio of CO₂ emissions per barrel (intensity), but that the overall production in barrels is increasing such that the total CO₂ emissions are still increasing.

According to [12], in-situ production with natural gas as fuel requires about 60 kilograms of CO₂E emissions per barrel on estimate. This estimate goes up to around 80 kg per barrel after taking into consideration burning residue for SAGD fuel, up to 70 kg per barrel when upgrading with natural gas, and up to 90 kg per barrel when upgrading with residue gasification.

Based on these estimates, a plant that produces 100,000 barrels of bitumen per day using natural gas would emit at least 6,000,000 kg of CO₂E per day or 2,191,500 tonnes annually, which is on par with 1990 levels for a typical operation. Emissions could be as high as 3,287,250 tonnes annually.

4.5.2 The Kyoto Protocol

Canada has been invaluable in the creation and evolution of the Kyoto protocol. After signing the initial United Nations Framework Convention on Climate Change in 1992, and the Kyoto Protocol, in 1997, it played an essential role in working out the technical details in Marrakech, Morocco, in 2001. Not only has it led the way and actively encouraged other countries, including Iceland, New Zealand, Norway and Switzerland, to sign the protocol, it has also agreed to donate €450 million to climate control funds.

However, Canada itself is divided on the subject. Although as a country it has whole-

heartedly supported greenhouse emission controls, the provinces are divided amongst themselves.

In ratifying the Kyoto Protocol in 2002, Canada has agreed to reduce greenhouse gas emissions by 6% relative to the 1990 level by 2012 [32] [12]. This will involve reducing Canada's annual emissions by as much as 240 megatonnes. Alberta, the hub of Canada's oil and natural gas production, will be hardest hit by these changes. The government's "Climate Change Plan for Canada" places the burden of a specified gas emission target that requires a 50% reduction by 2020 of specified gas emissions relative to 1990 levels [33].

A report released by the government of Alberta claims that the costs to the country will be between C\$23 and C\$40 billion a year and that the Canadian government is blind to the economic realities.

Canada's federal government expects the oil industry to achieve the targets set by the protocol by reducing emissions intensity of oil and gas production while continuing expansion [12]. However, as is demonstrated in Table 4.3, this is not a realistic expectation under the present systems, since reducing emissions intensity while growing at the rate companies currently are will still result in growing (rather than shrinking) emissions levels by 2012.

Under the status quo, this goal is literally impossible. Many Canadian industries believe that their competitiveness will be severely undermined by the changes, especially as the United States has chosen to opt out of the protocol. The measures encouraged under the federal government's plan will make products produced in Canada more expensive than those produced next door, in the more industry-friendly United States.

New systems will have to be developed to enable the realization of this idealistic goal. Companies are already testing cleaner fuels and CO₂ sequestration as means of lowering emissions, but none of them as yet have been drastic enough to enable Canada to realize its target emissions.

The nuclear option has the capacity to dramatically cut greenhouse gas emissions. A twin-unit ACR-700, an option discussed in the next section, eliminates the release of over 10 megatonnes of CO₂, when compared with generation of the same amount of energy using natural gas, and 300 megatonnes of CO₂ equivalent over 30 years. With a target reduction of 240 megatonnes annually, this option could bring the target significantly closer to realization.

4.5.3 Canada's Climate Change Plan

In 2002 and again in 2005, Canada's federal government outlined its three-step plan for reducing the country's overall greenhouse gas emissions by 270 megatonnes by 2012 [34]. It divides this goal into several areas where reductions can be implemented, many given appropriate budgets: The Climate Fund, The Partnership Fund, Large Final Emitters, Greenhouse Gas Reduction Programs, Carbon Sinks, Renewable Energy, Consumer Action, and Greening Government.

The oil and gas industry falls under the category of Large Final Emitters, whose portion of the goal is a reduction of 45 megatonnes. It is expected that the reduction of 36 of these will be achieved by 2012, and that companies in the industry will achieve this goal by either implementing in-house technologies to reduce their own emissions or by buying emissions "credits" from other companies in the industry, other domestic sources, or confirmed international reduction sources.

Figure 4.6 shows graphically just how ambitious the emissions reduction goals are. While the blue line shows how CO₂ emissions will increase if current trends continue, the red line indicates how emissions are meant to decrease under Canada's climate change plan. The two lines quickly diverge greatly, indicating how difficult it will be to close the gap. It should be noted that plants using nuclear fuel do not emit any greenhouse gases and thus suffer no cost or future uncertainty of cost for reducing emissions.

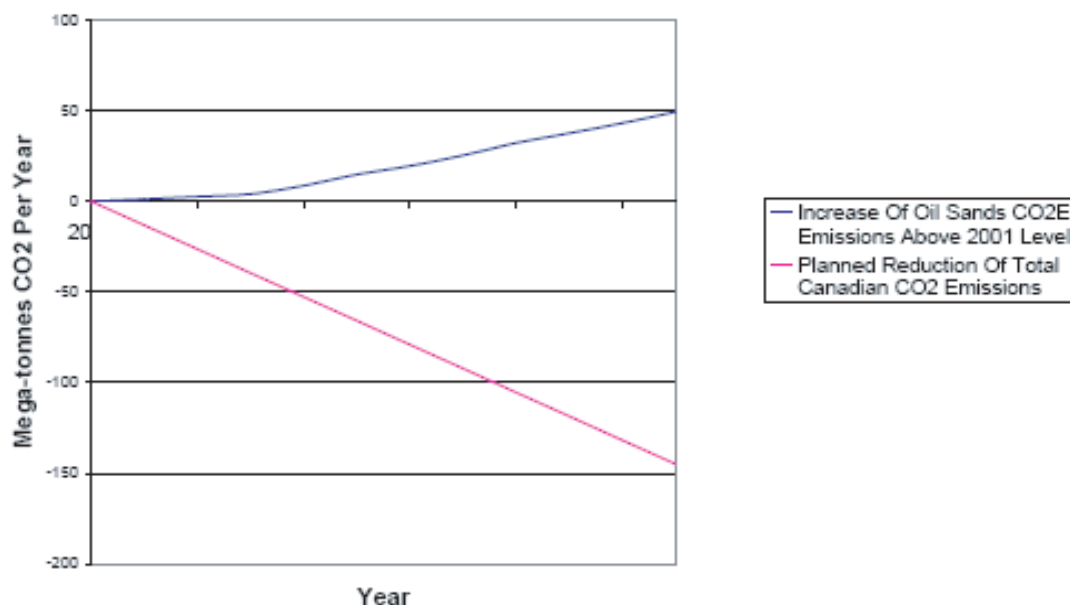


Figure 4.6: Oil Sands CO₂E Emissions and Need for Reductions Under the Kyoto Agreement [35]

4.5.4 The Cost of Emissions Reductions

The federal government is on record as stating that the cost of reducing greenhouse gases during the Protocol's first implementation period (2003 to 2012) will not exceed \$15/tonne of CO₂ produced. Thus many oil sands operations in the early stages of planning are concerned whether the cost of maintaining emissions standards will prove prohibitive.

The Canadian government is also in talks about developing its own environmental standards as an alternative to the Kyoto protocol, and the regional government of Alberta is developing its own emissions targets [32]. This makes it difficult for investors to estimate costs not only due to the fluctuating natural gas market but also the uncertainty in future costs of meeting emissions protocols.

The amount of greenhouse gas emissions, especially CO₂E, is a limiting factor in the growth of the oil sands industry. Using nuclear power as a fuel source is one solution to the problem, as further discussed in the following sections. Nuclear power does not emit greenhouse gases, so a nuclear plant used for bitumen extraction would not need to worry about trading credits, changing regulations, sequestration, or emissions reduction costs of any kind.

Chapter 5

Energy Requirements

5.1 Introduction

A myriad of systems have been implemented for in-situ processes. These facilities come in a variety of shapes and sizes, from small extraction facilities to massive extraction and upgrading plants. They can, however, be divided into three general categories: those that produce only process heat, those that produce process heat and electricity, and those that upgrade on site in addition to producing process heat and electricity. This chapter enumerates the steps involved in extracting the bitumen and calculates the energy requirements for each scenario.

In the first scenario, we produce only process heat. Electricity is taken from the Alberta electric grid and diluent is used to make the bitumen suitable to be piped away and refined elsewhere. The energy requirements for this process are relatively straight-forward, as they are derived solely from the thermal requirements of the extraction process.

In the second scenario we dilute bitumen with diluent, like scenario one, but we produce electricity in addition to process heat. In certain areas of Alberta, the transmission lines are somewhat unreliable. Furthermore, the large energy capabilities of a nuclear reactor enable this addition to be made with only the extra capital cost of the turbine systems.

The third and final scenario is a self-contained facility that produces its own electricity and process heat, and refines the bitumen on site to produce synthetic crude oil (syncrude). Using high temperature steam electrolysis, the facility will produce hydrogen, an essential component in bitumen refining, and upgrade the bitumen to syncrude.

We will tailor our thermal requirement calculations to a 100,000 bbl/day facility, a middle sized facility, so that we may compare each scenario under the same metric.

Following the analysis of the energy requirements, is a section describing the three recommended reactors for oil sands operations, and their benefits and drawbacks.

5.2 Scenario 1: Process Heat

The first scenario is the simplest of the three options; only process heat is produced. Electricity is drawn from the grid and diluted bitumen is shipped elsewhere for processing. In this scenario, all the energy produced by the reactor is passed to the SAGD loop.

Assuming a facility with a 100,000 bbl/day output, the following section calculates the range of energy requirements for this scenario, taking into account the quality of the well, as well as the pressures for the steam. The output steam to oil ratio (SOR) and the steam pressures are sufficient to give a close approximation of the requisite energy values. This range is then used to evaluate possible reactor choices for Scenario 1.

Figure 5.1 gives an approximate schematic of the extraction process, including the reactor, the steam generator, and the steam assisted gravity system input and output.

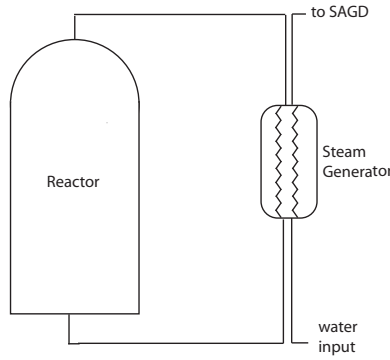


Figure 5.1: Process heat system

5.2.1 Flow Analysis

Positing a production facility of 100,000 bbl/day, the flow rate can be calculated. Given that one barrel of bitumen is equivalent to 0.208 m³, the following calculations give the time-averaged volume of bitumen extracted per second for the assumed facility:

$$\left(100,000 \frac{\text{Bbl}}{\text{day}}\right) \left(0.208 \frac{\text{m}^3}{\text{Bbl}}\right) = 20,800 \frac{\text{m}^3}{\text{day}} = 0.247097 \frac{\text{m}^3}{\text{sec}} \quad (5.1)$$

From this calculation, multiplying the bitumen rate by the SOR, the process requires between 0.48194 m³ and 0.72292 m³ of water per second. Assuming the density of water

at standard temperature and pressure is $1,000 \text{ kg/m}^3$, the flow rate for SAGD is between 418.94 kg/sec and 722.92 kg/sec .

For the purposes of this system, energy requirements will be provided in the pressure range from 2 to 6 MPa, at 80% steam quality. (Low quality wells operate at 2 MPa, and high quality wells operate at 6 MPa.) Given these values, the temperature of the SAGD input stream (the flow in the secondary loop as it leaves the steam generator, as seen in Figure 5.1) must be between 212.4°C and 276°C . Because of the inherent inefficiencies of steam generators, the reactor core outlet temperature must be at least 40°C higher than the necessary SAGD input stream temperatures. It can be assumed, for the moment, that the temperature of the primary loop as it enters the steam generator is at a minimum of 300°C .

The water recovered from the SAGD process is recycled and returned to the steam generator, significantly reducing the amount of energy necessary to reach the desired steam quality. The manner in which it is recovered ensures that the water is already pressurized, and is at approximately 170°C . With this data, the energy requirements of the system can easily be calculated.

The enthalpy difference between the SAGD flow and the recovered steam flow (in the secondary loop, the input and output flows of the steam generator) is $1,701.1 \text{ kJ/kg}$ at 2 MPa and $1,748.8 \text{ kJ/kg}$ at 6 MPa. Using the flow rate of water determined above, the megawatt requirement for a low performance (performance is determined by the SOR) well at 6 MPa is given by:

$$\left(722.7 \frac{\text{kg}}{\text{sec}}\right) \left(1748.9 \frac{\text{kJ}}{\text{kg}}\right) = 1,264 \text{ MW} \quad (5.2)$$

Because this calculation was performed for maximum pressure and minimum performance, 1,264 MWth is the maximum power necessary for this system. The same calculation was executed for the remaining pressures and SORs, giving a range of energy requirements as seen in Table 5.1.

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

Table 5.1: Range of thermal energy requirements for SAGD process heat

5.2.2 Optimal Reactors

Given these energy requirements, between 820 and 1,262 MWth, the optimal reactor for this process would need to produce at least 400 MWe. This assumes a conservative reactor efficiency of approximately 30%.

The requirements for the process heat of the SAGD system are relatively small compared to the possible output of a nuclear power station. Using the maximum requirements detailed in the previous section, the smallest viable light-water reactor is the AP600. Without another application for the heat produced by this facility, there will be a good deal of excess energy at the end of the process. Possible uses for this power are discussed at the end of this section.

Another potential reactor is the Pebble Bed Modular Reactor (PBMR). This reactor has a very small thermal output, making it ideal for a process heat only scenario.

AP600

The AP600 is described in great detail in Sections 6.3 and Appendix A.3, but for the purposes of the process heat calculations, Figure 5.2 gives a simple schematic of the flow of the primary loop of the reactor and its interface with the steam generator.

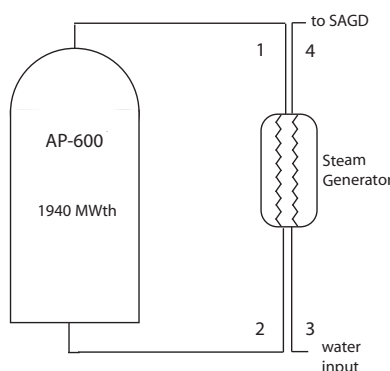


Figure 5.2: Westinghouse AP600

Although all previous applications of the AP600 have centered around the production of electricity, it is a simple matter to replace the secondary electricity loop with a SAGD system. The temperatures, pressures, and flow rates of the primary loop are identical for both an electricity system and the extraction process. Also the same steam generators used in electricity production can be used to produce the steam for the SAGD process.

All the inlet and outlet temperatures of this system can be seen in Table 5.2.2, corresponding to the points referenced in Figure 5.2.

Four PBMRs

Point	Temperature (°C)	Pressure (MPa)
1	316	15
2	224	8.2
3	170	2-6
4	276	2-6

Table 5.2: Temperatures and pressures for various points in the AP600

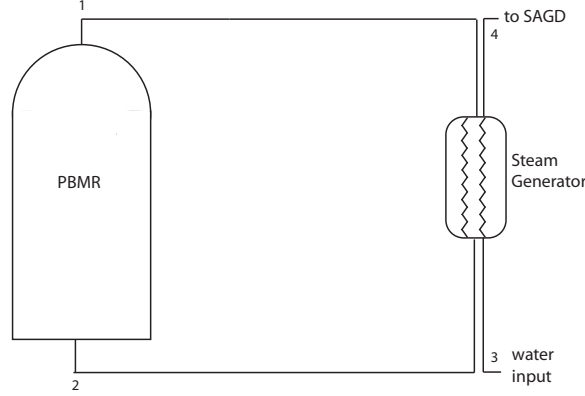


Figure 5.3: PBMR for Process Heat

A Pebble Bed Modular Reactor would also make a reasonable choice as a reactor to handle the process heat demands. PBMRs are discussed in Section 6.2; for more detail see Appendix A.2. Since PBMRs generally have small thermal output of around 400 MWth each, the number of PBMRs used can be scaled for a particular site.

As mentioned earlier, the power demands of the process heat are 1,264 MWth. The PBMR secondary flow is 98.7% efficient, so the actual demand is 1,281 MWth [36]. Rounding calculations to the nearest integer, we find that we need four PBMRs to meet the power demands of a 100,000 bbl/day plant.

$$(1,281 \text{ MWth}) \left(\frac{1 \text{ PBMR}}{400 \text{ MWth}} \right) = 3.20 \text{ PBMRs} \quad (5.3)$$

The small unit size of the PBMR allows it to be scaled directly to the needs of the plant. For example, if only 400 MWth of process heat were necessary, only one PBMR would be used. Such a scaling mechanism ensures that the reactor power is used optimally. The scaling is particularly important if the production of a plant is to be increased over time, or if other plant capabilities, such as electricity or hydrogen production, are desired. The modularity of the PBMR allows a plant to be easily upgraded to accommodate higher production needs; one could construct another PBMR module if a plant were to need an additional 400 MWth.

5.3 Scenario 2: Electricity Production

In many cases, it may be feasible, even beneficial for the reactor to produce electricity in addition to process heat. If the extraction facility is relatively isolated and without an accessible grid, or if the extraction plant is large enough to make purchasing electricity prohibitively expensive, it is financially advantageous to produce electricity on site. The benefits of producing electricity include improved utility economics, added supply reliability, and reduced transmission line loss.

In this section, the energy requirements for producing electricity in addition to process heat is determined. First, the electric power need is deduced for the 100,000 bbl/day reference plant. Then, combining this requirement with the demands of the process heat only scenario, as described in the previous section, the total thermal output is calculated for the system. This range of values is then used to suggest appropriate reactors for Scenario 2.

5.3.1 Electricity Demand

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

Table 5.3: Electric power demand for 110,000 bbl/day facility

These values are for an extraction facility slightly larger than our posited 100,000 bbl/day “typical plant,” but the requirements can be scaled up and down depending on the size of the plant. These numbers give an idea as to the sources of the demand, and give some substance to our assumptions about energy demand. The AECL asserts that 250 MWe is sufficient to maintain a 100,000 bbl/day facility without upgrading capability. For the sake of consistency, the calculations will continue to be performed for this “typical” facility.

5.3.2 Electricity and Process Heat Systems

There are three options for the setup of a system for producing electricity in addition to steam. The first option, as seen in Figure 5.4(a), splits into three loops. The primary loop, which contains only the reactor and the steam generator, carries the reactor coolant

through the steam generator. The secondary loop, with the turbine and the steam generator, contains the steam necessary for powering the turbine. The second steam generator produces the steam required for the SAGD system.

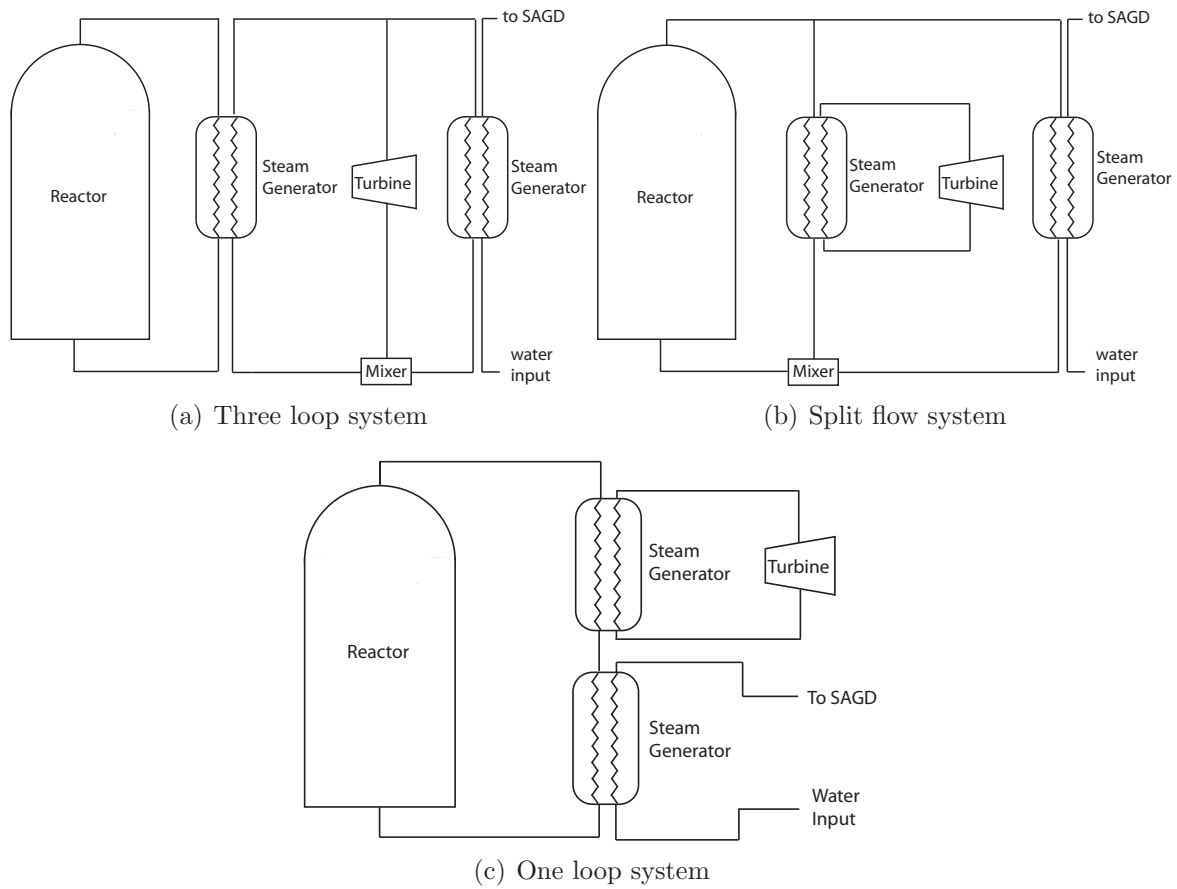


Figure 5.4: Options for electricity production systems

This option can be eliminated trivially because of the difficulty involved in forcing steam through a steam generator, which would be necessary for the second loop to work properly. Although it is feasible, very large surface areas are required to provide sufficient heat exchange, creating large inefficiencies and making it impractical and economically unfeasible.

The second option, seen in Figure 5.4(b), involves splitting the primary loop flow, with both feeds going to steam generators, the first to power the turbine, and the second to produce steam for the SAGD process. There is a disadvantage associated with this system, because of the flow inefficiencies caused by splitting the feed while maintaining the pressure. However, the advantage is that it can be done with a lower temperature reactor because the system feeds the same temperature coolant into both loops. The temperature of the reactor must only reach the saturation temperature for the pressure chosen.

The third option, shown in Figure 5.4(c), does not have this advantage. The water entering the SAGD steam generator has to be at least 300°C. As a result of the thermal transfer in the heat exchanger in the turbine loop, the output feed from the reactor would have to be significantly higher than 300°C. This option is only feasible with a high temperature reactor.

The same issue arises with this option as with the split feed system. The efficiency of the steam generator for the turbine loop must be quantified before the requirements can be determined. The calculations have already been done for the SAGD steam generator, so once the efficiency is calculated, the electricity requirement can be converted to a thermal requirement and added to the SAGD thermal requirement, giving the total MWth value for this two step process.

5.3.3 Flow Analysis

With a range from 1,400 to 1,600 MWth for the process including electricity, a reactor of at least 800 MWe is necessary for the system. For the split feed option, a lower temperature light water reactor can be used. For the single loop system however, while the same range is applicable, a higher temperature reactor is necessary.

ACR-700

The AP600 does not have a large enough capacity to be a viable option for the production of electricity in addition to process heat. Instead the larger ACR-700 is used. This Canadian reactor can supply the necessary heat to run a turbine system and provide process heat using a single reactor.

In the past, the ACR has been used exclusively for electricity production. A simple schematic of this system can be seen, in Figure 5.5.

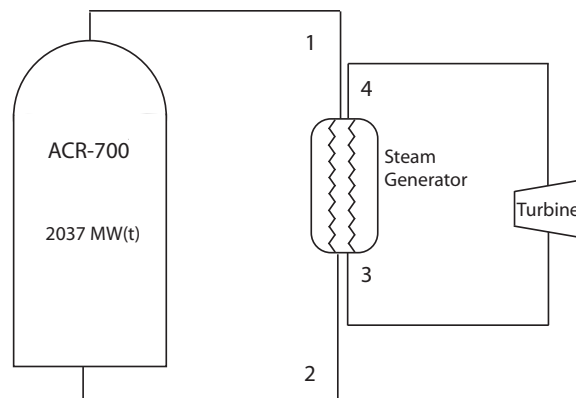


Figure 5.5: ACR-700 Conventional Power System Design (Source: [37])

The optimal design for providing both electricity and process heat was introduced in Section 5.3.2. Without turning to a high temperature reactor, the most efficient design splits the primary coolant loop, diverting a fraction to a steam generator powering the SAGD system (as shown in Figure 5.4(b)).

An important choice that both simplifies the calculations and lowers the capital costs involved in construction of the facility is the decision to use identical steam generators for both processes. The specific advantages of this choice are discussed later in this section. As can be seen in Figure 5.6, the primary loop splits after it leaves the reactor, and is recombined after it is passed through the steam generator.

The steam generator used in this system is described in Section 5.2.2.

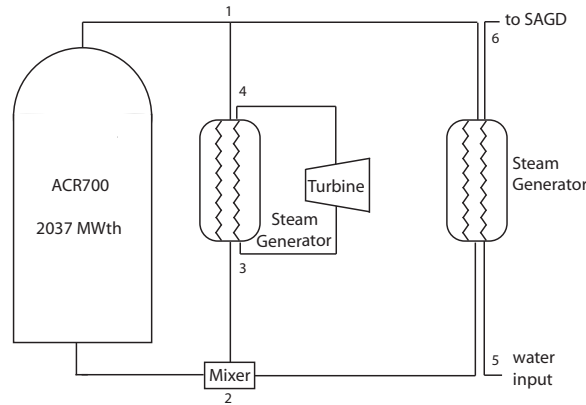


Figure 5.6: ACR-700

Table 5.4 includes the inlet and outlet temperatures and pressures of the numbered points in the schematic. The split flow of the primary loop, along with the similar temperature requirements for both the turbine system and the SAGD system, ensure that points 1 through 6 will have the same temperature and pressure values for both systems, Figures 5.5 and 5.6.

Point	Temperature ($^{\circ}\text{C}$)	Pressure (MPa)
1	326	11.9
2	279.5	11.9
3	215	6.4
4	279	6.4
5	170	6.2
6	279	6.2

Table 5.4: Temperatures and pressures at various points in the ACR-700 (Source: [37])

The primary system is only about 99.85% efficient, therefore 0.15% of the heat is lost before the coolant in the primary system reaches the steam generator. For simplicity

here, it is assumed that the piping inefficiencies are the same for the trip to both the turbine steam generator and the SAGD steam generator. Once the coolant reaches the steam generator, no assumptions are necessary. According to the technical specifications of the ACR-700, the steam generator is 99.8% efficient. Given that the steam generators used in both processes are the same, this value is constant.

The maximum heat necessary for the SAGD system was shown to be 1,264 MWth. The steam generator for the SAGD loop, seen here as SG₂, must produce 1,264 MWth. Given the 99.8% efficiency of the steam generator, 1,266.5 MWth must reach the generator for this value to be achieved.

The ACR-700 is rated at 2,037 MWth. As a result of the 99.85% efficiency of the reactor system in transporting the coolant to the steam generator, only 2,033.95 MWth of the initial power reach the steam generators. Once the 1,266.5 MWth calculated above are removed from the flow stream, just 767.45 MWth remain for the turbine loop. With the 99.8% efficiency of the steam generators, we can determine that the turbine steam generator, SG₁ in Figure 5.6, produces 765.91 MWth.

The turbines are discussed in more depth in Section E. For now it is sufficient to use the efficiency values given in the ACR-700 technical documents, indicating that the typical electricity production systems used run with a 37% efficiency neglecting the loss of the system, and a 34.56% efficiency including the pumping losses associated with the secondary system. Multiplying these efficiencies by the thermal power produced by SG₁, the steam generator for the turbine loop, gives 283.96 gross and 265.23 net MWe. This is over the 250 MWe maximum necessary for the assumed 100,000 bbl/day extraction facility, demonstrating the viability of this option.

The final step is to calculate the mass-flow ratios of the split feed system. The calculations in this step are simplified by the fact that the characteristic heat capacity at constant pressure for the two steam generators of the system, as well as the temperatures of the system are constant between the two feed loops. The energy of the system is given by the simple relation, $E = \dot{m}c_p\Delta T$. The mass flow is given in the ACR-700 technical specifications as 4,440 kg/sec. Since the temperature drops across the steam generators are identical for the two steam generators, and the heat capacities are consistent through those temperature drops, the ratio of the mass flows is equal to the ratio of the energies and can be calculated using a simple comparison, as demonstrated in the following equations. E_1 , E_2 , \dot{m}_1 , and \dot{m}_2 are the energies and mass flows of the flow streams of the turbine and process heat steam generators. E_t and \dot{m}_t are the energy and mass flow at the output of the reactor.

$$\frac{E_1}{E_t} = \frac{767.45 \text{ MWth}}{2,033.95 \text{ MWth}} = 0.38 = \frac{\dot{m}_1}{7,130 \text{ kg/sec}} = \frac{\dot{m}_1}{\dot{m}_t}$$

$$\dot{m}_1 = 2,690 \text{ kg/sec}$$

$$\frac{E_2}{E_t} = \frac{1,266.5 \text{ MWth}}{2,033.95 \text{ MWth}} = 0.62 = \frac{\dot{m}_2}{7,130 \text{ kg/sec}} = \frac{\dot{m}_2}{\dot{m}_t}$$

$$\dot{m}_2 = 4,440 \text{ kg/sec}$$

Even though dividing the demand among the reactors is efficient and minimizes the number of reactors necessary, there are conditions where dedicating reactors to particular tasks is advantageous. For example, it may be desirable to centralize electricity and hydrogen production such that these centralized reactors can provide the necessary electrical power and upgrading demands of a grid of reactors that generate process heat. In such a scenario, if all available oil reserves are extracted from a particular site, additional sites can be established concurrently with or following the operation of that site.

Centralizing the processing sites as to reasonably minimize the distance the bitumen has to travel in the case of upgrading or to minimize the extent of the power grid to be established is in the best interest of such layouts. Regardless of the desired placement, in a situation where two reactors to generate process heat are desired, a single location can be established as the site for electricity production and/or upgrading.

An ACR-700 can provide 2,037 MWth. As earlier, the electric demands translate to a power of 767.45 MWth. To satisfy this demand, a single reactor is necessary. The process heat demands are the same as earlier, 1,264 MWth. One reactor would thus also be used for the process heat. Unlike the earlier scenario, where a single reactor could satisfy both the electric and process heat power demands, two reactors are now necessary. However, this design offers modularity and the ability to add additional process sites.

Another means of dealing with the use of two reactors is to scale the electricity and bitumen production such that a larger capacity of the reactors are used. By doing so, the daily production of bitumen can be increased and additional electricity can be sold to the grid.

Five PBMRs

Both split configurations and reactors that are dedicated to either process heat or elec-

tricity can be used for the PBMR due to the low power output per reactor. The single loop configuration does not maximize the utilization of possible power output as well as the split configuration, but this effect can be reduced.

There is an inherent problem with the use of a single loop system, as depicted in Figure 5.4(c). The heat in the loop of a PBMR is effectively used to the point until the loop temperature is lowered to 100°C. Since the return temperature of the water used in processing is 170°C, no further heat can be extracted from the loop of the PBMR at this point.

The electricity and the process heat generation loops can be maintained as separate entities in a split flow system. Similar calculations to the ones used for the ACR-700 can be used here. The process heat necessary for the 100,000 bbl/day plant is 1,264 MWth, and the electricity necessary is 250 MWe. The equivalent power in MWth for the electricity can be calculated by dividing the power in MWe by the efficiency of the cycle.

$$P_e = \frac{400 \text{ MWe}}{0.41 \frac{\text{MWe}}{\text{MWth}}} = 610 \text{ MWth} \quad (5.4)$$

The total power necessary is the sum of the power for the electricity and the process heat.

$$P_t = P_h + P_e = 1,874 \text{ MWth} \quad (5.5)$$

$$P = \frac{P_t}{\eta} = \frac{1,874 \text{ MWth}}{0.987} = 1,899 \text{ MWth} \quad (5.6)$$

$$(1,899 \text{ MWth}) \left(\frac{1 \text{ PBMR}}{400 \text{ MWth}} \right) = 4.75 \text{ PBMRs} \quad (5.7)$$

Assuming that PBMRs with outputs of 400 MWth are used, five reactors are necessary to meet the process heat and electricity demands. Note that the separated flows requires fewer reactors than the combined flows. A theoretical explanation for this observation is the fact that the process heat loop in this setup is only drained to 500°C, the temperature of the inlet stream to the reactor. Because of this, the only inefficiency witnessed by the stream is that of the heat exchangers and secondary elements, which are relatively small compared to the inefficiencies of the turbine, compressor, and Brayton cycle. The high efficiencies of the process loop implemented make the system with the dedicated loops more efficient than the proposed alternative.

5.4 Scenario 3: Hydrogen, Electricity, and Process Heat

The addition of hydrogen to the bitumen is a costly step in the refining process. Given the high heat available with the use of a fission reactor, it is possible to produce hydrogen and partially upgrade the bitumen economically on site.

The thermal requirements for hydrogen production are small, 80 MWth. The step that significantly increases the energy demands for this process is the 310 MWe necessary for the hydrolysis. Additionally, the system must take into account the electricity demands of the upgrading facility that uses the hydrogen produced. After describing in detail the upgrading steps this facility will perform, the following section calculates the energy demands for the system as a whole, taking into account both the thermal energy necessary for the hydrolysis, the electric power necessary for the entire process, and the process heat energy requirements.

Using the energy range determined, the optimal reactors for Scenario 3 are discussed in Section 5.4.3.

5.4.1 Hydrogen Systems and Energy Requirements

Hydrogen Needs for Bitumen Upgrading

Syncrude Mildred Lake Upgrader (including changes due to expansion project) has bitumen processing capacity of 540,500 bbl/calendar day and requires 677,000,000 standard ft³ per day of hydrogen [38].

$$\frac{677,000,000 \text{ standard ft}^3/\text{day}}{540,500 \text{ bbl}/\text{day}} = 1,253 \text{ standard ft}^3 \frac{\text{of hydrogen}}{\text{bbl of bitumen processed}} \quad (5.8)$$

The high temperature steam electrolysis system requires a starting temperature to begin the reaction. This temperature is similar enough to the input temperature of the SAGD system that they can be coupled in parallel. Hydrogen production requires both thermal and electrical energy. 80 MWth and 310 MWe is sufficient to provide enough hydrogen to upgrade the bitumen from the 100,000 bbl/day facility.

Table 5.5 details the energy requirements for an upgrading facility. Most of these requirements were accounted for in the section on electricity production. However, the second row in the table includes the electricity demands for upgrading, approximately 100 MWe more than was necessary for the extraction facility alone. These values were

obtained from the Mildred Lake application, and are slightly larger than the 100,000 bbl/day reference plant.

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

Table 5.5: Electric power demand for 110,000 bbl/day facility

5.4.2 Hydrogen Requirements

There are two system options for producing hydrogen for the production facility. In the first, illustrated by Figure 5.7(a), all coolant flows through the heat exchanger for the turbine loop. After it leaves the heat exchanger, it splits into two feeds, one running through the SAGD steam generator, and the other running through the hydrogen production system steam generator. Because these two systems require the same temperatures, they can run in parallel. The hydrogen system described in the previous section requires 80 MWth, and the SAGD requirements were calculated in Section 5.2.1. Given these two values, all that needs to be determined is the ratio of the mass flow rates between the SAGD and the hydrogen system feeds. Additionally, hydrogen production requires an additional 310 MWe and upgrading requires 100 MWe on top of that.

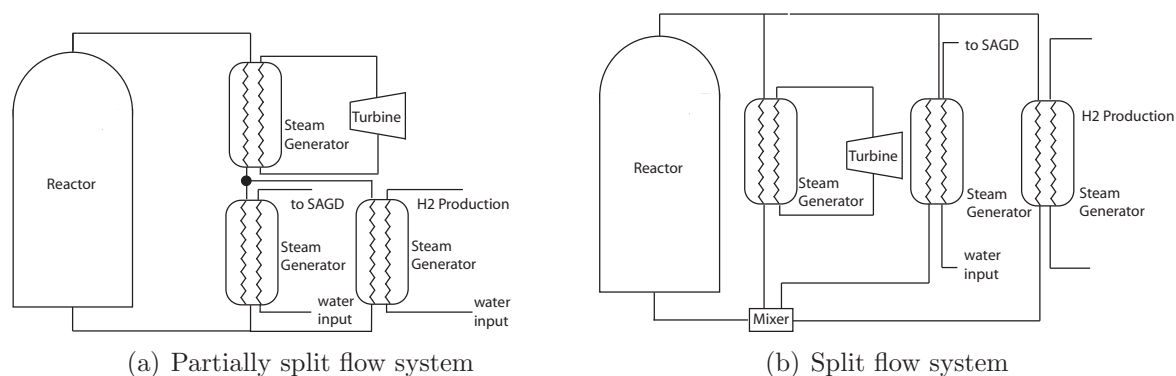


Figure 5.7: Options for hydrogen and electricity production systems.

The second option, seen in Figure 5.7(b), splits the primary feed into three loops, running through three steam generators, supplying steam for each plant component; SAGD, electricity production, and hydrogen production.

Using these values, and assuming again a typical 100,000 bbl/day production facility, the MWth can be determined, ranging from 2,495 to 2,800 MWth. With the high temperatures necessary for the first option, the only feasible design employs the PBMR system. However the light water reactors are entirely appropriate for the second option. The split feed means that a lower temperature reactor can be used effectively. Both options will be more thoroughly analyzed in the following section.

5.4.3 Optimal Reactors

There are two options for producing hydrogen using a light-water pressure reactor. When used in parallel with another of the same model, both the ACR-700 and the AP600 produce sufficient heat for SAGD steam; electricity for the extraction facility, the upgrading plant, and the electrolysis process; and heat for the hydrogen production.

In both scenarios, the two plants are run in parallel, so the MWth produced and the flow rate from the reactor are simply doubled. The same process heat is required, and the same pressures, temperatures, and enthalpies are maintained for both systems. All the temperatures seen in Tables 5.2.2 and 5.4 hold for the processes described below.

The only changes from the system described in Section 5.3.3 are the additions of an 80 MWth requirement for HTSE and 410 MWe for electrolysis and an upgrading facility. Therefore, the calculations for both systems are nearly identical to the ones performed in the previous section 5.3.3.

Two ACR-700s

Figure 5.8 illustrates the split feed system design chosen for the hydrogen production processes.

The power from two reactors is 4,074 MWth. The thermal power required for the high temperature steam electrolysis is 80 MWth. Taking into account the inefficiencies of the steam generator, 80.2 MWth of what is produced by the reactor is needed by the hydrogen system. The SAGD system is identical to the previous process, requiring 1,266.5 MWth. Summing these requirements, and taking the difference between the result (1,344.2 MWth) and the output of the reactor (including inefficiencies, 4,065.9 MWth) gives the energy that remains to power the turbine (2,721.3 MWth).

With 2,722 MWth going exclusively to the turbine steam generator, and net efficiency of 34.56% specified in the ACR technical documents, this plant can produce as much as 940 MWe. Assuming that the extraction facility requires 250 MWe, as posited at the

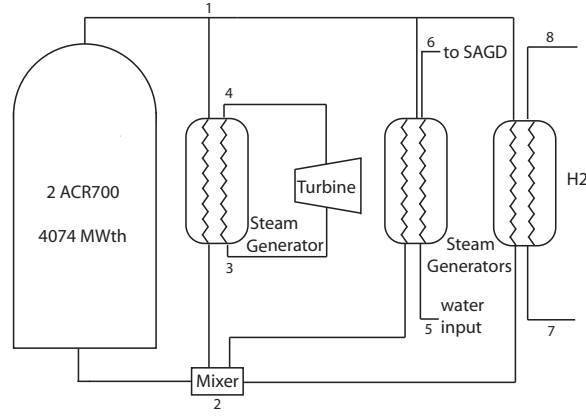


Figure 5.8: Two ACRs

beginning of this section, the electrolysis requires another 310 MWe, and the upgrading facility requires 100 MWe, the total energy requirements of the facility is 660 MWe. The ACR-700s in parallel easily meet the power demands of the facility.

Following the same prescription described in the previous section, the energy ratios can be used to determine the mass flow ratios on account of the constant temperature drop and heat capacity of the steam generators. The mass flow rate from the combined reactor is double the individual flow rate, at 14,260 kg/sec. E_1 , E_2 , E_3 , \dot{m}_1 , \dot{m}_2 , and \dot{m}_3 are the energies and mass flows of the flow streams of the turbine, the process heat, and the hydrogen production steam generators. E_t and \dot{m}_t are the energy and mass flow at the output of the reactors.

$$\frac{E_1}{E_t} = \frac{2,721.3 \text{ MWth}}{4,065.9 \text{ MWth}} = 0.67 = \frac{\dot{m}_1}{14,260 \text{ kg/sec}} = \frac{\dot{m}_1}{\dot{m}_t}$$

$$\dot{m}_1 = 9,539 \text{ kg/sec}$$

$$\frac{E_2}{E_t} = \frac{1,266.5 \text{ MWth}}{4,065.9 \text{ MWth}} = 0.31 = \frac{\dot{m}_2}{14,260 \text{ kg/sec}} = \frac{\dot{m}_2}{\dot{m}_t}$$

$$\dot{m}_2 = 4,440 \text{ kg/sec}$$

$$\frac{E_3}{E_t} = \frac{80.2 \text{ MWth}}{4,065.9 \text{ MWth}} = 0.02 = \frac{\dot{m}_3}{14,260 \text{ kg/sec}} = \frac{\dot{m}_3}{\dot{m}_t}$$

$$\dot{m}_3 = 281 \text{ kg/sec}$$

Two AP600s

The power from two AP600 reactors is 3,880 MWth. As with the previous system, the thermal power required for the high temperature steam electrolysis is 80 MWth. Figure 5.9 illustrates the split feed system design chosen for the hydrogen production processes using two AP600s.

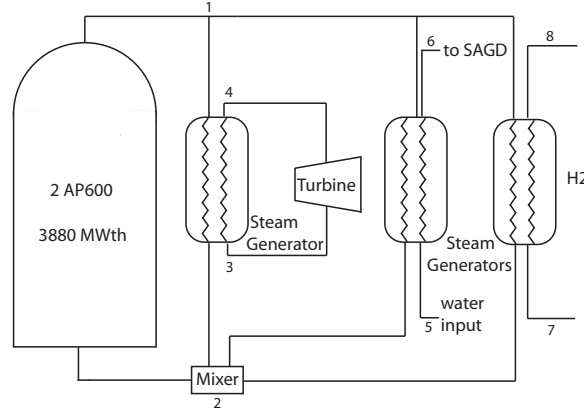


Figure 5.9: Two AP600s

To account for the inefficiencies of the steam generators used in the AP600, we can assume inefficiencies approximately the same as those of the steam generators used in the ACR-700 system. Although those detailed in the Westinghouse specifications are not described to the same level of accuracy as those used in the technical documents for the ACR reactor system, the same calculations can be performed, with the caveat that the system will only be viable given an efficiency above a certain value.

What is known is the efficiency of the system between the reactor and the steam generators. With a 99.6% efficiency, 3,866 MWth is available for use by the steam generators. With 80 MWth required for the electrolysis, and 1,264 MWth required for the SAGD, only 2,522 MWth remains to run the steam generator for the turbine loop.

As in the system described in the previous section, 660 MWe are necessary to run all the plant applications. This means that for the two plant system to function properly with the AP600, the steam generator/turbine system must have a combined efficiency of at least a 26.2% efficiency. Only the poorest quality systems will run at a lower efficiency, so the system will be viable in nearly every scenario.

The same formulae can be applied to determine the mass flow ratios. Again, this is a simple matter as a result of the constant temperature drop and heat capacity of the steam generators. The total mass flow rate of the system, the individual rate doubled, is 8,438 kg/sec. E_1 , E_2 , E_3 , \dot{m}_1 , \dot{m}_2 , and \dot{m}_3 are the energies and mass flows of the flow streams

of the turbine, the process heat, and the hydrogen production steam generators. E_t and \dot{m}_t are the energy and mass flow at the output of the reactors.

$$\frac{E_1}{E_t} = \frac{2,522 \text{ MWth}}{3,866 \text{ MWth}} = 0.67 = \frac{\dot{m}_1}{8,438 \text{ kg/sec}} = \frac{\dot{m}_1}{\dot{m}_t}$$

$$\dot{m}_1 = 5,505 \text{ kg/sec}$$

$$\frac{E_2}{E_t} = \frac{1,264 \text{ MWth}}{3,866 \text{ MWth}} = 0.31 = \frac{\dot{m}_2}{8,438 \text{ kg/sec}} = \frac{\dot{m}_2}{\dot{m}_t}$$

$$\dot{m}_2 = 2,759 \text{ kg/sec}$$

$$\frac{E_3}{E_t} = \frac{80 \text{ MWth}}{3,866 \text{ MWth}} = 0.02 = \frac{\dot{m}_3}{8,438 \text{ kg/sec}} = \frac{\dot{m}_3}{\dot{m}_t}$$

$$\dot{m}_3 = 175 \text{ kg/sec}$$

The same dedicated reactors as described earlier can be applied when upgrading is also desired. In this scenario, two possible options are available for dedicated reactors. In the first option, the centralized reactor handles both the electricity and upgrading demands. The second option separates the electricity and upgrading units. Although the separation allows for the separate shutdown of the reactors, in the first case, if only a single reactor is required for the pair of processes, two reactors would be necessary to satisfy the setup in the second case.

The electric demands once the hydrogen production are accounted for rise to 767.45 MWth. To satisfy this demand, a single reactor is necessary. The process heat demands are the same as earlier, 1,264 MWth. One reactor would thus also be used for the process heat. Unlike the earlier scenario, where a single reactor could satisfy both the electric and process heat power demands, two reactors are now necessary. However, this design offers modularity and the ability to add additional process sites.

The calculations for the reactor distribution when using a single reactor to handle both the electric and upgrading demands is calculated simply by scaling the earlier calculation where electricity production and process heat production are separated.

Eight PBMRs

The total heat necessary between the process heat and the heat for the HTSE is 1,344 MWth, and the total electricity necessary is 660 MWe. The equivalent power in MWth for the electricity can be calculated by dividing the power in MWe by the efficiency of the cycle.

$$P_e = \frac{660 \text{ MWe}}{0.41 \frac{\text{MWe}}{\text{MWth}}} = 1,610 \text{ MWth} \quad (5.9)$$

The total power necessary is the sum of the power for the electricity and the process heat.

$$P_t = P_h + P_e = 2,954 \text{ MWth} \quad (5.10)$$

$$P = \frac{P_t}{\eta} = \frac{2,954 \text{ MWth}}{0.987} = 2,993 \text{ MWth} \quad (5.11)$$

$$(2,993 \text{ MWth}) \left(\frac{1 \text{ PBMR}}{400 \text{ MWth}} \right) = 7.48 \text{ PBMRs} \quad (5.12)$$

$$(5.13)$$

This analysis shows that eight reactors are used for the configuration where the process heat, electricity production, and the upgrading of the syncrude are desired.

reactors proves to be more efficient. The total heat necessary between the process heat and the heat for the HTSE is 1,344 MWth, and the total electricity necessary is 660 MWe. The equivalent power in MWth for the electricity can be calculated by dividing the power in MWe by the efficiency of the cycle.

$$P_e = \frac{660 \text{ MWe}}{0.41 \frac{\text{MWe}}{\text{MWth}}} = 1,610 \text{ MWth} \quad (5.14)$$

The total power necessary is the sum of the power for the electricity and the process heat.

$$P_t = P_h + P_e = 2,954 \text{ MWth} \quad (5.15)$$

$$P = \frac{P_t}{\eta} = \frac{2,954 \text{ MWth}}{0.987} = 2,993 \text{ MWth} \quad (5.16)$$

$$(2,993 \text{ MWth}) \left(\frac{1 \text{ PBMR}}{400 \text{ MWth}} \right) = 7.48 \text{ PBMRs} \quad (5.17)$$

$$(5.18)$$

This analysis shows that eight reactors are used for the configuration where the process

heat, electricity production, and the upgrading of the syncrude are desired.

The reactors can also be distributed such that certain reactors are dedicated to the production of process heat or electricity. If such a configuration is desired, five reactors are required for electricity generation.

$$P_h = 1,344 \text{ MWth} \quad (5.19)$$

$$P = \frac{P_h}{\eta} = \frac{1,344 \text{ MWth}}{0.987} = 1,362 \text{ MWth} \quad (5.20)$$

$$(1,344 \text{ MWth})\left(\frac{1 \text{ PBMR}}{400 \text{ MWth}}\right) = 3.40 \text{ PBMRs} \quad (5.21)$$

$$(5.22)$$

Four reactors are necessary for the process heat. In total, a dedicated reactor configuration will required 8 reactors, the same as the number of reactors required if the setup were not dedicated. In such a scenario, the benefits of a dedicated setup and the fact that no additional reactors compared to the other case are necessary makes the dedicated reactors desirable.

Chapter 6

Nuclear Reactor Design Options

Existing nuclear technologies can meet all the energy demands of an oil sands processing plant, as outlined in the three scenarios of Sections 5.2 to 5.4. Several nuclear reactor designs produce enough thermal power for the steam requirements of SAGD. In given configurations, some can also satisfy primary outlet temperature requirements to efficiently produce electricity, H_2 for upgrading, and process heat. In addition, our analysis in Chapter 9 shows that a nuclear reactor can provide for the needs of a SAGD plant at a smaller cost than a natural gas plant can.

Ten different reactor designs were studied, and three reactors were selected as the most viable for integrating with oil sands facilities: the “Advanced Passive” AP600 by Westinghouse, Advanced CANDU Reactor (ACR-700) by Atomic Energy of Canada Ltd. (AECL), and the Pebble Bed Modular Reactor (PBMR) by Pebble Bed Modular Reactor Ltd.

The most salient features of each chosen design, and their specific benefits and drawbacks for integration with an Oil Sands plant are delineated in this section. For ease of comparison, a chart is included in Section 6.4 to outline the reactors back to back. More details on the three designs are given in Appendix A. And summary of the other seven reactors considered and the reasons for not selecting them is given in Appendix B.

6.1 Advanced CANDU Reactor (ACR-700)

The 700 MWe, 2,037 MWth, Advanced CANDU Reactor (ACR-700) is a reactor designed by Atomic Energy of Canada Limited (AECL) that is an improvement on the CANDU-6 reactors. CANDU reactors have a well established genealogy; the first prototype CANDU reactor, ZEEP, reached criticality in September 1945, and the first commercial CANDU

reactor, Pickering A, began operation in 1971. AECL has a good reputation for building reactors to cost and schedule [6]. It is smaller than the CANDU-6. The ACR-700 calandria, which includes the horizontal core and moderator vessel, is 50% smaller than the CANDU-6 calandria. The ACR-700 also has a new fuel design, and has a negative coolant void coefficient [39].

It has a nominal gross output of 753 MWe with a net output of approximately 703 MWe. It is a pressurized water reactor(PWR)/pressurized heavy water reactor (PHWR) hybrid that is light water cooled and heavy water moderated, has a horizontal fuel lattice, and facilitates online refueling. The light water coolant exits the core at 326°C. It uses CANFLEX fuel bundles that contain 2.0% by weight slightly enriched Uranium (SEU). Figure A.4 shows a picture of the core vessel.

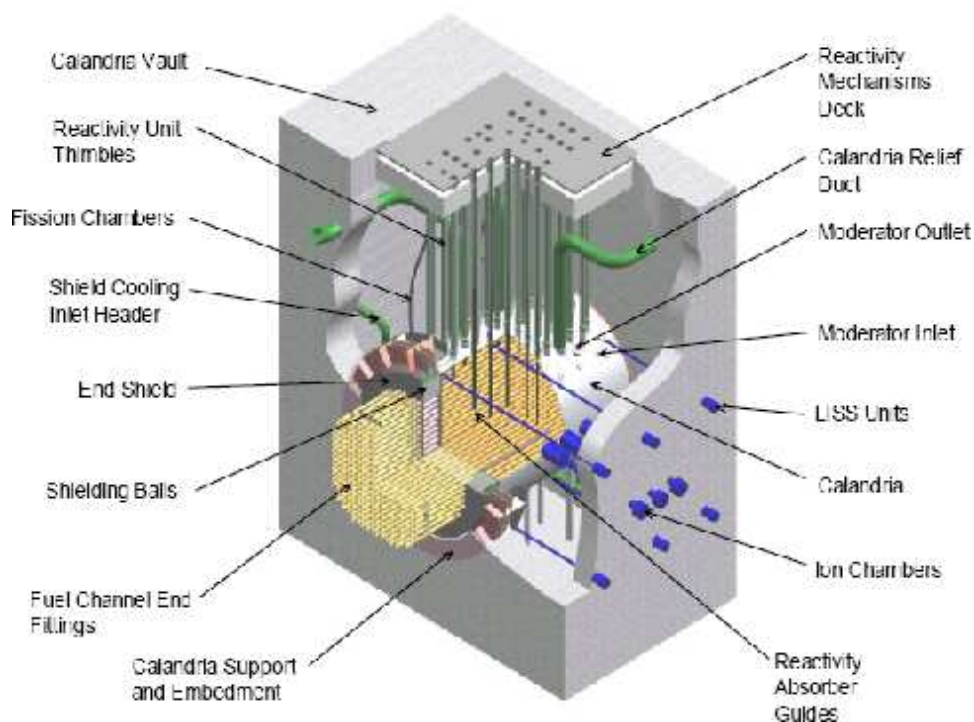


Figure 6.1: ACR-700 Core Housing Design

6.1.1 Design Specific Benefits for Oil Sands

The ACR-700 has some features that make it particularly well-suited for use in a Canadian oil sands extraction project. Specifically, since the ACR-700 is of Canadian design, and the pre-licensing process is underway in Canada, it would be politically the easiest plant to build. Atomic Electric Canada Ltd. (AECL) has the support of the Canadian government; it builds and operates all of Canada's nuclear power facilities, and the federal government contributes significant funds to its research initiatives.

The ACR-700 design is heavily based on the CANDU-6 design, for which AECL has already developed a preferred set of manufacturers. Those same companies would be well-prepared to begin construction on the new ACR, which would shorten the total time needed to build the first plant. As compared with the CANDU-6, the ACR-700 has a smaller core and is more modular, so it would be easier to ship and to assemble on-site. The ACR-700 is designed to require a smaller staff than the current CANDU's, and to reduce the planned outage time to 21 days every three years. The forced outages are expected to be less than 2%, so a yearly capacity of 93–95% is considered obtainable. The online refueling feature of the ACR makes it possible to run the plant for a longer time than a traditional LWR without interruption, which is beneficial for the oil sands operations [40].

6.1.2 Design Specific Drawbacks for Oil Sands

One of the disadvantages of the ACR-700 is that it is not a high-temperature reactor, so its electrical efficiency is not as high as the Generation IV nuclear plant designs; AECL optimistically quotes its efficiency as 37%, which is higher than most reactors in use today, but not as high as the PBMR. The ACR-700 is a low-burnup reactor, with discharged fuel being about 20 MWd/kgU, which leads to a higher Pu-239 content than PWR's such as the AP600 or AP1000. This is unfavorable from the standpoint of nuclear non-proliferation safeguards. In comparison with the PBMR, the ACR is a much larger reactor that would be more difficult to transport to the site for construction. To enable rail transportation, some of the module assembly that would typically be done in-factory would likely need to be done on-site, increasing the construction costs and on-site labor demands.

Due to its light-water cooling system and heavily water-dependent EECS, the ACR requires a large water supply, which is logistically difficult in the Athabasca region in northern Alberta. Due to its online refueling and active safety systems, it requires a larger full-time staff than automatically refueling or batch refueling reactors, or those with passive safety systems. The SEU used in the CANFLEX fuel bundles for the ACR might be scarce at first, since it is not manufactured widely, but as more reactors are built and demand for it grows, it will be less of a difficulty.

6.2 The Pebble Bed Modular Reactor (PBMR)

The story of the PBMR began in 1993 when Eskom, the South African electricity supply company, started investing in its design [41]. By 1997, the initial concept design and the

cost analysis were completed. The results supported the viability of the PBMR as an electricity supplier, and soon after, the Eskom Council formally classified the PBMR as a “priority project.” In 2002, Limited was created by Eskom, the Industrial Development Corporation (IDC), British Nuclear Fuels Limited (BNFL), and Exelon to create and market the PBMR design [42]. Today the design is complete, and as of 2002 an application for an Early Site Permit (ESP) was submitted to the USNRC. Also, in June 2003, the South African Department of Environmental Affairs and Tourism approved the 110 MWe PBMR design. Plans are currently underway to build a demonstration plant at Koeberg near Capetown, South Africa [43].

The PBMR module is a 165 MWe, 400 MWth reactor. It uses inert helium gas as primary coolant, and graphite as moderator. Its fuel consists of loose tennis ball-sized pebbles that each contain approximately 11,000, 8% Uranium-235 enriched UO_2 microspheres. The core operates at much higher temperatures than normal reactors, around 900°C . The high temperature helium is sent directly to a gas turbine after exiting the core. The PBMR boasts higher efficiencies ($\sim 41\%$ efficient) [44] than LWRs due to the higher temperature coolant. This is beneficial because with higher the efficiencies the fuel can be used more economically; the less fuel burnup for the same number of kWh.

The primary mission of the PBMR design is to eliminate the possibility of expelling excess radiation beyond the site boundary (400 m). It strives to achieve this by using characteristics inherent to the nuclear fission process to maximize safety; the designers wanted to eliminate the need for an active engineered safety system. See Figure 6.2 for a diagram of the reactor system.

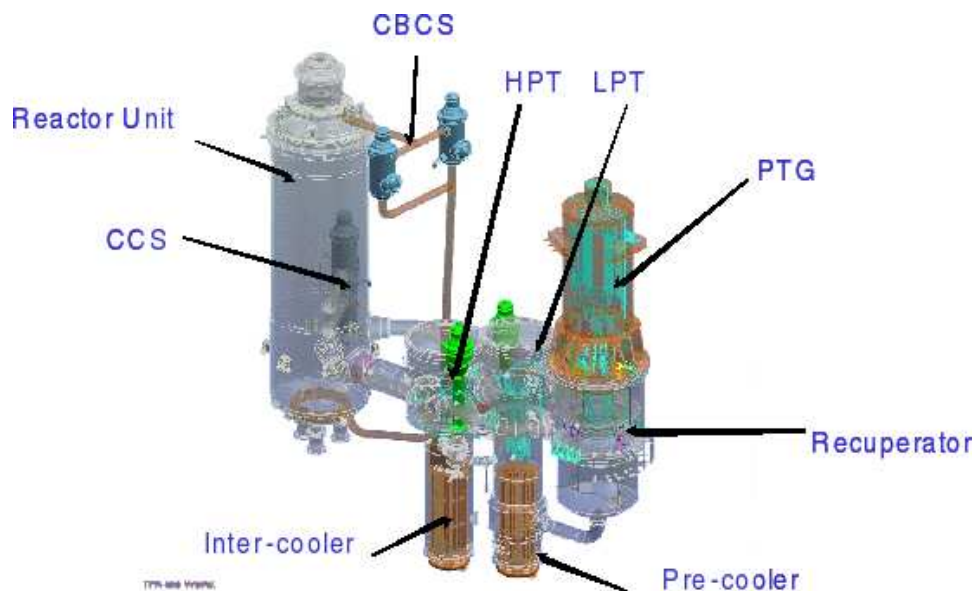


Figure 6.2: PBMR Main Power System (Source: [44])

6.2.1 Design Specific Benefits for Oil Sands

Of the three chosen designs, the PBMR has the most technological innovations by far. These innovations are advantageous to oil sands applications in many ways. First of all, they enable the PBMR to reach very high core outlet temperatures; temperatures almost three times as high as other designs. This is very helpful in Scenario 3 for hydrogen production. In fact, as discussed in Section 5.4.3, an 8-module PBMR plant is the only design capable of supporting the first, partially split, flow system.

Another innovation that benefits the system is the use of helium as primary coolant. As discussed in Section A.2.4, heat transfer qualities of helium make it a good working fluid. Because of this, the PBMR boasts higher thermal efficiencies than most designs; it has a thermal efficiency of approximately 40%. The use of helium is also beneficial because it reduces the plant's water needs. Both the ACR-700 and the AP600 have very high water needs for regular operation, and in the case of an accident where emergency core cooling is needed. Studies have been performed that demonstrate the PBMR's abilities to dump excess heat to the atmosphere via natural convection, thus making an emergency core cooling system unnecessary. Helium is also radiologically and chemically inert. In the event that a primary coolant pipe bursts, helium will carry very little radioactivity as it is expelled from the pipe.

The PBMR fuel design also provides several safety innovations. The fuel microspheres were designed to provide several barriers to the release of radioactive materials. The fuel pebble graphite matrix provides even more protection from radionuclide release.

Another benefit of the core/fuel design is that it allows for online refueling. This way, the bitumen extraction system will never need to stop on account of the reactor. The PBMR only needs to shutdown for 30 days for maintenance every 6 years.

Finally, the small unit size of the PBMR is beneficial to the oil sands extraction system because it allows a splitting of flows. For example, if the extraction system requires 4 PBMR units, 3 can be used for process heat, 1 for electricity production, and 1 for Hydrogen production. This independence of the modules can make the plant more efficient because all of the energy needs can be tailored specifically to the application. Also, this could potentially allow the oil sands plant to run constantly, for any maintenance could be performed one unit at a time.

6.2.2 Design Specific Drawbacks for Oil Sands

Unfortunately, the PBMR technological design innovations create almost as many problems as they solve. A good portion of the PBMR design has never been implemented in

Canada before, and thus has never been reviewed for licensing by the Canadian Nuclear Safety Commission (CNSC). The CNSC charges the licensee according to the amount of time and effort they spend reviewing a design. This would make the PBMR more costly to license. Also, the time required to complete the licensing process would be much longer than a design that the CNSC is more familiar with, such as the ACR-700. Along those same lines, the PBMR lacks the genealogy of established commercial power plants that the ACR-700 and the AP600 have. It will take time for the PBMR construction process to reach the dependability of a mass production plant.

The helium system also has its drawbacks. Past High Temperature Gas Cooled Reactors (HTGRs) have shown that helium can be costly and difficult to maintain; the helium storage pressures are quite high.

Finally, the fuel pebble is still under investigation. The fuel microsphere and pebble needs to be very robust to maintain its integrity in the hot temperatures of the core. It is unclear what the rate of failure in the microspheres is. Some studies claim that half of the fuel microspheres will experience damage during normal operation, and of those damaged microspheres, 10–15% will release fission products into the bulk of the pebble. Yet, other studies claim less than a 5% rate of microsphere failure [45]. These studies make the conservative assumption that any fission product release into the bulk of the pebble will leak into the coolant and eventually into the environment, so this failure rate may not be much to worry about if the outer fuel pebble graphite layer maintains its integrity. Nevertheless, more studies need to be performed.

6.3 The Westinghouse AP600

Westinghouse Electric Company led the international team that designed the AP600, an advanced pressurized water reactor (PWR). The core, reactor vessel, internals and fuel are mostly similar to currently operational Westinghouse PWRs. Like the ACR-700 the AP600 has a very dependable, well established genealogy. According to PRIS, the International Atomic Energy Agency (IAEA) power reactor database, the PWR is the most popular reactor design in the world. Of the 442 operational reactors worldwide, 214 are PWRs [46]. The safety systems are the most innovative, relying on passive features, driven by forces of nature. The “AP” in the name stands for “Advanced Passive.”

The AP600 is rated at 600 MWe net electrical output, 1,940 MWth nuclear steam supply system (NSSS) power and 1,933 MWth core power. It is light water cooled and moderated. The primary coolant exits core vessel at approximately 316°C. The fuel is usually enriched Uranium, with 4.20% by weight Uranium-235 and 0.04% by weight Uranium-234. It has a plant design life of 60 years without replacing the reactor vessel,

and its overall plant availability is 90–93%, including outages [47]. The AP600 plant is more modular than all of its parent PWR designs, increasing ease of construction in the Athabasca region.

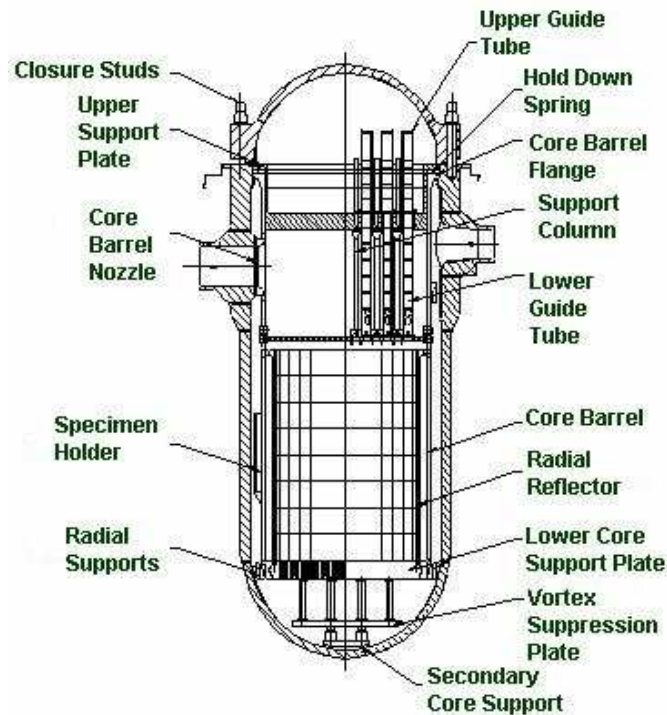


Figure 6.3: AP600 Reactor vessel (Source: [48])

6.3.1 Design-Specific Benefits for Oil Sands

The AP600 counts with passive safety features and simplified designs that reduce costs considerably, as well as Westinghouse’s decades of experience with PWRs and thorough reviewing by the United States Nuclear Regulatory Commission, which can help in speeding regulatory activity up in Canada.

This design’s construction time is less than three years, less than other advanced reactors, which allows an early start of operations.

6.3.2 Design-Specific Drawbacks for Oil Sands

Considering that Canadian nuclear regulatory authorities are unfamiliar with designs other than local ones, the AP600 is at a disadvantage. Politically, this could lead to opposition to the design and longer and costlier licensing processes. Practically, it might translate into difficulties in getting prepared labor for construction and operation of the

facility. Also, it is likely that some aspects of the design have to be adapted to Canadian standards and to the rather unstable surface, which might cause further delays.

Furthermore, not being a high-temperature reactor, its efficiency is lower than for other advanced designs. Moreover, this is the least modular of the three proposed designs, which could lead to problems in transporting the components to the site, especially considering the terrain.

Additionally, relative to the other options, this design's water demands are high, it does not count with online refueling and would need a larger staff for daily operation and maintenance.

6.4 Comparison Chart of Salient Reactor Features

Attribute	ACR-700	AP600	PBMR
Thermal Power (MWth)	2,037	1,940	400
Electric Power (MWe)	703	600	165
Primary Coolant	Light Water	Light Water	Helium
Primary coolant outlet temperature	326°C (619°F)	316°C (600°F)	900°C (1,652°F)
Efficiency	37%	31%	41%
Safety	Redundant shut-down and cooling systems	Passive for 72 hours	Passive Safety
Economics	More competitive than natural gas except for “process heat only” case.	More competitive than natural gas in all cases.	Lowest capital and O&M costs, highest fuel costs. Least expensive for “process heat only” case. More competitive than natural gas in all cases.
Government Support	Clear Federal support in Canada	Not supported in Canada, but supported in US	Not supported in Canada or the US. There is some pebble bed experience in Germany, and work being done in South Africa.
Public support	Some support in Canada; Canadian gov’t, CNSC, and Canadian people more likely to support Canadian technology	Not supported in Canada because it is not a native technology	Not supported in Canada because it is not a native technology
Construction time and modularity	Modular and 60 months for first plant, eventually 42 months.	Least modularized of the three. 50 large structural pieces, and 250 rail-shippable parts. 60 months expected before first start-up.	Highly modularized design

Attribute	ACR-700	AP600	PBMR
Regulatory Oversight	CSNC has experience with the CANDU reactors and with AECL	Has been certified in the US, but the CNSC has no experience with LWRs	Has begun pre-certification in US, but the CNSC has no experience with HTGRs
Waste and Spent Fuel	Intended for use with the Canadian MACSTOR dry storage system. Spent fuel is higher in Pu than typical LWR spent fuel.	Can be stored safely on-site for up to a century. Same type of waste, but much less per megawatt than for typical PWRs.	Fuel pebbles are stored in a canister. Fuel pebble coating provides prevention of fission product release. Main drawback is that low power density fuel will take up to 18x more volume than LWR spent fuel.
Refueling time and outages	Automatic refueling. 21 day shutdown every 3 years. 95-97% capacity factor.	18 month refueling cycle. 90% capacity factor.	Online refueling. Short and infrequent outages: 30 days every 6 years. Availability/Capacity factor = 90–95%
Burn-up	20 MWd/kgU	48 MWd/kgU	90 MWd/kgU
Proliferation	High Plutonium production because of SEU/NU.	No special measures	Very difficult to separate Plutonium due to the microspheres and pebbles. Also, because burnup is so high, spent fuel makes for bad weapons material.

Attribute	ACR-700	AP600	PBMR
Design simplicity	Based on CANDU's, but there is a lot of plumbing.	Simplified design for an LWR, based on proven designs.	Many fewer parts than a traditional reactor, but incorporates many design innovations as well.
Life of Plant	60 yrs	60 yrs	60 yrs
Materials	Requires a containment, but concrete modules are pre-cast.	Requires concrete poured containment	Does not require containment - confinement only.
Production Line	Developed from CANDU reactor construction	No development	No development, except that fuel is produced overseas.
Water Demand	High (for coolant and ECCS)	High (for coolant and long term emergency cooling)	Low (only for secondary cycle)

Table 6.1: Reactor Comparison

Chapter 7

Licensing

7.1 General Process

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 regulation, 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.

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.

The CNSC is generally regarded as less prescriptive and patronizing than its American counterpart. The applicant, rather than the Commission, chooses the scopes of discussions, based on the issues it wants resolved.

Licensing nuclear-powered oil extraction systems will represent a challenge initially, considering that existing regulatory mechanisms will have to adapt to this new application of nuclear technologies. While this may take time and money for the first implementations,

it will become increasingly efficient for subsequent instances, as the CNSC familiarizes itself with how the proposed systems address safety issues.

7.1.1 License Applications

Canadian law [49] requires separate license applications for different activities. Every application related to a Class I nuclear facility, such as the reactor of interest, must include a description of the site; plans of the facility; evidence of the site owner's authorization of the activity; a proposed quality-assurance program; identification of hazardous substances and proposed policies for the control of any associated dangers to the workers, the public and the environment; a proposed program to inform the community living close to the site about the activity and its effects; and a proposed plan for the facility's decommissioning.

In addition, each type of license application requires more information, as outlined in the following sections. The first three are needed for the start of operations. The fourth license, even though it must be filed later, when the reactor is to be decommissioned, should also be accounted for at the start of operations. A fifth type of license, for abandoning the site, would only have to include the results of the decommissioning and the environmental monitoring program. Simultaneous applications for different activities, typically site preparation and construction, can be allowed.

License to Prepare Site

An application for a license to prepare a site for a reactor would also need to include a description of the site evaluation and of the preparatory work completed or needed on the site; an assessment of the hazard posed to the site by external factors like natural phenomena and human activity; and the identification of potential effects of the activity on the environment and on people's health and safety, as well as measures to minimize them. Any future site approval by the CNSC will require a comprehensive environmental assessment prepared in accordance with the provisions of the Canadian Environmental Assessment Act, as explained in Section 7.1.2.

License to Construct

The application for construction licensing must contain a description of the proposed design of the facility and its structures, systems and equipment; a construction program and schedule; a preliminary safety analysis report; the measures to ensure Canada's compliance with relevant international agreements; the identification of potential hazardous

effects resulting from the construction, operation and decommissioning of the facility; the relevant measures to mitigate them; and the proposed program for personnel training and qualification.

License to Operate

The operating license is a very detailed specification of the operational limits and specifications of the conditions governing all process systems, safety systems and safety-support systems. This license application requires a description of all the systems and equipment and their operating condition; a program for their commissioning; a final safety analysis report; the proposed policies for operation and maintenance of the facility, for handling of hazardous substances, minimizing negative health, safety and environmental effects of operation, commissioning and possible accidents; the measures to prevent acts of sabotage; and the detailed program for personnel training and qualification, including responsibilities, requirements and achieved results.

License to Decommission

The National Safety and Control Act requires the holder of a license to operate a nuclear facility to make provision for the decommissioning of existing or proposed installations. Therefore, a company planning to build a reactor must have decommissioning plans; a verifiable estimate of the costs of implementing these plans; and financial measures to ensure that the costs of the decommissioning will be met.

However, an application for the license to decommission a facility only has to be filed when this process becomes necessary. Such an application would have to include a detailed description of the process and its schedule; an assessment of the extent of the facility's nuclear contamination; the measures to minimize any negative effects of the relevant hazardous substances; the proposed personnel qualification and training requirements; and a description of the expected condition of the site after the decommissioning.

7.1.2 Environmental Assessment

An environmental assessment must be completed before any licensing decision can be made. This is regulated under the Canadian Environmental Assessment Act, and the evaluation must conclude that, given the appropriate measures are taken, the project in question is unlikely to result in significant damage to the environment. The assessment starts with the application for the license to prepare the site and the evaluation should cover the entire life cycle of the nuclear plant.

7.1.3 Fee Structure

Before each fiscal year, the CNSC estimates the annual fee to be paid by the applicant or licensee, in quarterly installments, for the year's cost of the regulatory activity for the relevant facility, as outlined in the Commission's Cost Recovery Fees Regulations. Adjustments are made after the end of the year to account for the actual cost.

The CNSC seems to try its best to accommodate the licensee. According to its Cost Recovery Fee Program:

"Fees are determined and charged...in a way that benefits both the CNSC and the licensee. Through joint planning and the up-front exchange of information: The CNSC can receive feedback from licensees; and Licensees can see directly what they are being charged for; paying only for the regulatory oversight they receive" [50].

For an initial facility application for which there is no estimated fee, the applicant has to pay a C\$25,000 deposit, after which the CNSC would calculate the corresponding annual fee. Payments would still be quarterly and the deposit amount would be subtracted from the invoices respectively.

Since the main facility of interest is a Class I nuclear facility, the applicant, and subsequently the licensee, would have to pay mostly Regulatory Activity Plan Fees, which include the cost of direct licensing activities plus a fraction of the cost indirect activities. The regulatory activity plan explains the regulatory effort for the facility.

For the 2005-2006 fiscal year, preliminary calculations result in average regulatory fee payments of approximately C\$3.7 million for each single-unit power reactor in Canada, while an average of around C\$4.7 million is estimated for each multiple-unit reactor [51].

The CNSC was asked for estimates of the duration of the licensing process and costs for the reactors of interest. While no design-specific reply was given, according to the Director of the Advanced Reactor Projects Division, "preliminary estimates show that it could take ten or more years from the filing of the application to the in-service date of the plant" [52]. There are two main sources of uncertainty for the estimate. First, the activities carried out by the applicant, since some can run in parallel with the licensing process, like site preparation, construction and parts fabrication. Second, activities related to environmental assessment, which could be subjected to public scrutiny.

7.1.4 Record-Keeping

After an applying company is awarded a license, it must keep records of the results of any environmental monitoring programs required by the license. A licensee operating

a nuclear reactor must also retain records, for ten years after the expiration date of the license to abandon, of operating and maintenance procedures; the results of the commissioning, inspection and maintenance programs; and amounts and characteristics of nuclear radiation and nuclear and non-nuclear hazardous substances. Furthermore, the licensee has to keep a record of each worker's training and qualification status, until five years after the end of the person's employment [49].

7.1.5 Nuclear Incident Liability

In the case of a nuclear incident, the holder of the license to operate the installation is absolutely and exclusively liable for any third party damage, regardless of fault or negligence, as outlined in the Nuclear Liability Act [53]. This does not hold if the damage results from "an act of armed conflict in the course of war, invasion or insurrection" or if the injured third party causes the incident intentionally.

The licensee must hold basic insurance against this liability for an amount up to an allowed maximum of C\$75 million, as prescribed by the CNSC for each facility, plus supplementary insurance for the difference between that amount and the allowed maximum. The Canadian government would fund any third party compensation beyond the maximum.

The Canadian maximum is very low with respect to international standards. In the United States, for example, the licensee must hold insurance for US\$30 million and, in case of a nuclear incident anywhere, every power reactor in the country must pay up to US\$95.8 million, as regulated by the Price-Anderson Nuclear Industries Indemnity Act. Congress would fund any further damage compensation. Also, the members of the Organization for Economic Cooperation and Development (OECD) are in the process of increasing the available compensation from €350 million to €1.5 billion [54].

In the past decade, a couple of bills have been read in the Canadian Parliament trying to amend the Nuclear Liability Act. In 1996, it was proposed to change the maximum insurance to C\$320 million; in 2003, the bill called for an increase to C\$1.1 billion for that year, with annual adjustments thereafter [55]. Neither succeeded, but it is likely that similar proposals will be made in the future. The adoption of such bills would increase the total costs for the licensee.

7.1.6 Nuclear-Hydrogen Plant Co-Location

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.

Having the widest range of flammability of all combustible gases (4.1–75% by volume), a very wide detonability range (18.3–59% by volume), a large mean free path and a large buoyancy factor, hydrogen is easily ignited and, once this happens, fire will propagate quickly. This represents a hazard that cannot go unnoticed near a nuclear reactor.

Two combustion types can occur: deflagration and detonation. In the former case, the combustion wave front is subsonic; in the latter, it is supersonic, and the damage is typically larger. A hydrogen combustion event can be a serious threat to the integrity of the nuclear plants structures.

However, according to [56], “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. Out of the proposed reactors, the PBMR is the only one designed to be built underground. The selected reactor design will affect the calculations, since the containment integrities are different for each. Also, minimizing the time of storage of hydrogen in the plant would reduce the maximum available volume of hydrogen for detonation, which would mitigate the separation needs.

The minimum safe separation distance between the plants will be in the order of 100 meters, depending on the factors considered above. Using HTSE for hydrogen production, as proposed, rather than less-developed thermochemical methods, gets rid of problems with chemical dispersion. However, if such methods were deemed more preferable in the future, separating the nuclear plant’s control room from the rest of the plant so that it is further away from the hydrogen one would help address the chemical dispersion issue [57].

7.2 Design-Specific Issues

The CNSC documents and Canadian law do not describe the licensing program of a specific nuclear reactor design. They outline the licensing process and the general regulatory

measures needed, and the way costs are divided and calculated, but to get an exact cost to license a specific reactor design, one must make a proposal to discuss directly with a CNSC representative. This is because every nuclear facility requires a different amount of regulatory activity.

7.2.1 ACR-700

The CNSC has begun a pre-licensing review of the ACR-700, which has been divided into two phases: Early Identification of Issues for Resolution and Assessment of Licensability.

In the first phase, the CNSC will identify the key licensing issues by assessing AECL's plans in the areas of safety methodology, design requirements, and research and development. It will then prioritize these issues in order of importance, and subsequently produce an Interim Screening Report which identifies issues and (where possible) agreed success paths.

During the second phase, a detailed review of the ACR-700 design from the perspective of potential licensing issues identified in the Interim Screening Report will be carried out, and a Final Design Assessment Report will be produced. The Report is not a license nor does it legally bind the CNSC to issue a license. It is only intended to give AECL reasonable assurance, if supported by the review findings, that the design is licensable in Canada or that it would be licensable under given conditions.

Since Canada only has a suitability-for-operation determination and not a design certification process, it will most likely be the first to license the ACR-700. The AECL is in conversations with several sites in Canada, and hopes to begin the two-year environmental assessment process by the end of 2005, and to gain approval by late 2006 or early 2007.

In addition to working with Canada, the AECL has also been working closely with the United States' NRC over this pre-application period to define the issues that need to be resolved. Apparently, the AECL has come away from recent discussions with NRC staff confident that a 43-month schedule from submission of the application to final rulemaking on the design certification is achievable.

Politically and economically speaking, the ACR-700 has an advantage over the other reactors in that it is manufactured by a Canadian company, AECL. To locals, the construction of the ACR-700 means more jobs opening up in the workforce, and more money in the economy from the revenue of the oil sands plant. Also, even though the ACR-700 is a new design, most of the technology is based on CANDUs, which the Canadian people are familiar with. The PBMR and the AP600 are both newer and more foreign to the

Canadians, so PBMR Ltd. and Westinghouse will have to invest more manpower and money in public relations to gain acceptance for their designs [6].

7.2.2 PBMR

Because of the unfamiliarity of the CNSC with the Pebble Bed Modular Reactor design, one can expect that the CNSC will need to devote more time to studying the regulatory needs of the PBMR, at least initially. Of the three designs studied in this report, the PBMR has the most technological innovations. This should also burden the licensing process for this design, lengthening its duration and increasing manpower needs. This would lead to higher costs than for the same process for a more familiar design such as an Advanced CANDU Reactor. However, subsequent PBMR models should not be as difficult to license, with an existing template to follow.

Canadian regulations require nuclear reactors to be able to withstand internal or external accidents or “malevolent events” like a terrorist attack, which could be a concern for the PBMR. While there is a radioactive material containment system, its design does not include a conventional containment building similar to those of traditional North-American reactors. The PBMR has protective structures designed to withstand aircraft crashes or earthquakes, but the CNSC might judge the design vulnerable to such events, given the unfamiliarity with the design.

In parallel, the PBMR has started the design certification process in the United States, which could provide valuable feedback to address licensing issues in Canada.

7.2.3 AP600

The regulations regarding the integrity of protective structures in cases of accidents or attacks can also be a problem for the AP600. Its design involves having a very thin steel containment wall that would allow emergency convection cooling between a flooded reactor and the atmosphere around the shell. While there is a concrete shield building surrounding the containment, the reactor might still be judged vulnerable to terrorist attacks such as a plane crash or an explosion. While the CNSC does not have specific requirements for the containment wall thickness, this can hurt any licensing application assessments. The lack of extra shielding also conflicts with general safety requirements that require that multiple barriers be present to prevent the uncontrollable escape of radioactive material, and may lead to failure of passing structural integrity tests that are designed for reactors with thicker containment walls.

In parallel, the Final Design Approval for the AP600 has already been completed in the United States by the NRC, whose regulations are generally more stringent than the Canadian ones. However, the CNSC is much less familiar with light-water reactors than for the usual CANDU reactors, which would likely translate to greater regulatory needs in terms of time and, hence, costs.

Chapter 8

Siting

8.1 Site Obstacles

Certain challenges are present when siting an in-situ SAGD facility, regardless of whether a nuclear reactor or a natural-gas fired reactor is used. It is necessary to take into account the obstacles present at the site before implementing a reactor.

8.1.1 Lease Boundaries

The design of an SAGD facility is restricted by the shape of the land and the boundaries of the plot, which are determined by a Canada Lands Surveyor according to the Canada Lands Surveys Act. Companies wanting to drill either exploratory wells or recovery wells must have explicit provisions allowing them to drill deeper than 1000 feet. At present, 29 companies hold leases in the McMurray formation. Figure 8.1 shows some of the plots held in the Athabasca Region. [58]

For the purposes of minimizing the distance of piping steam and bitumen, an ideal layout for a facility might be one in which several wellpads extend radially from a central processing facility. Unfortunately, the lease boundaries often prohibit such a layout. This is the case with OPTI's Long Lake project. Figures 8.2(a) and 8.2(b) illustrate the awkward layout of this lease. The design layout of the wellpads is constrained to the relatively narrow confines of the lease.

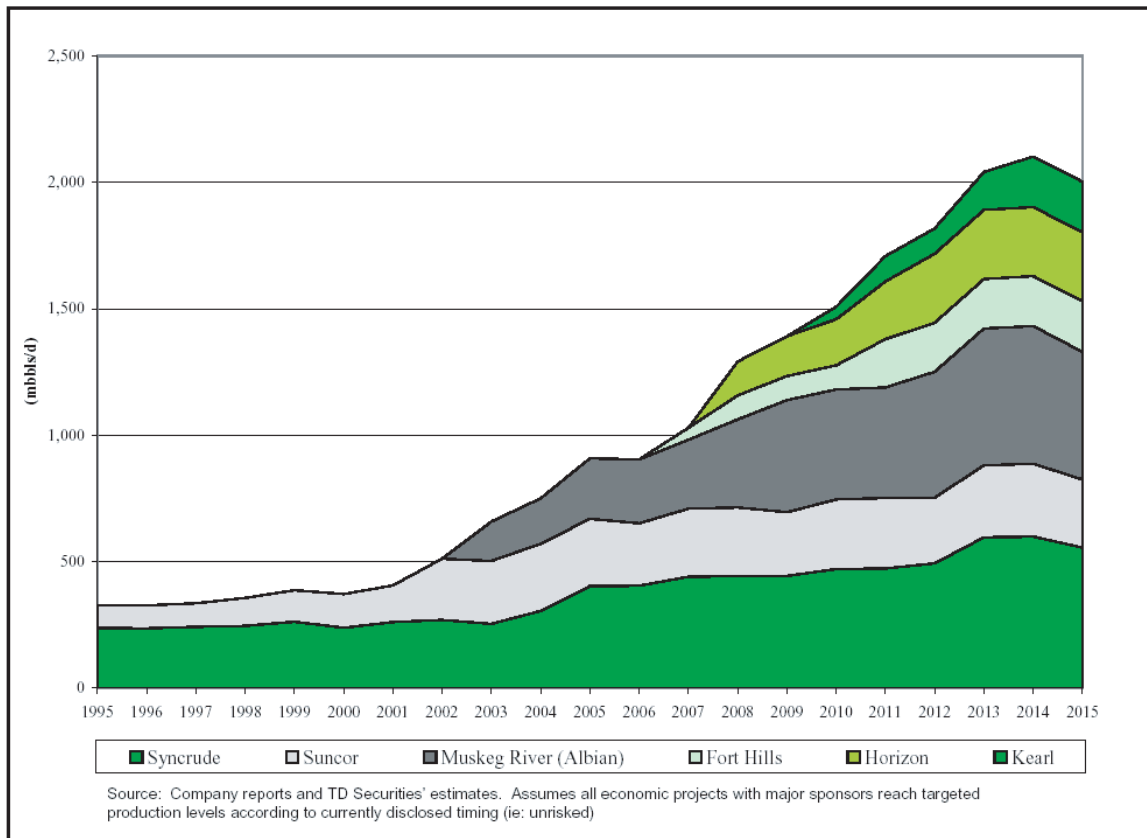


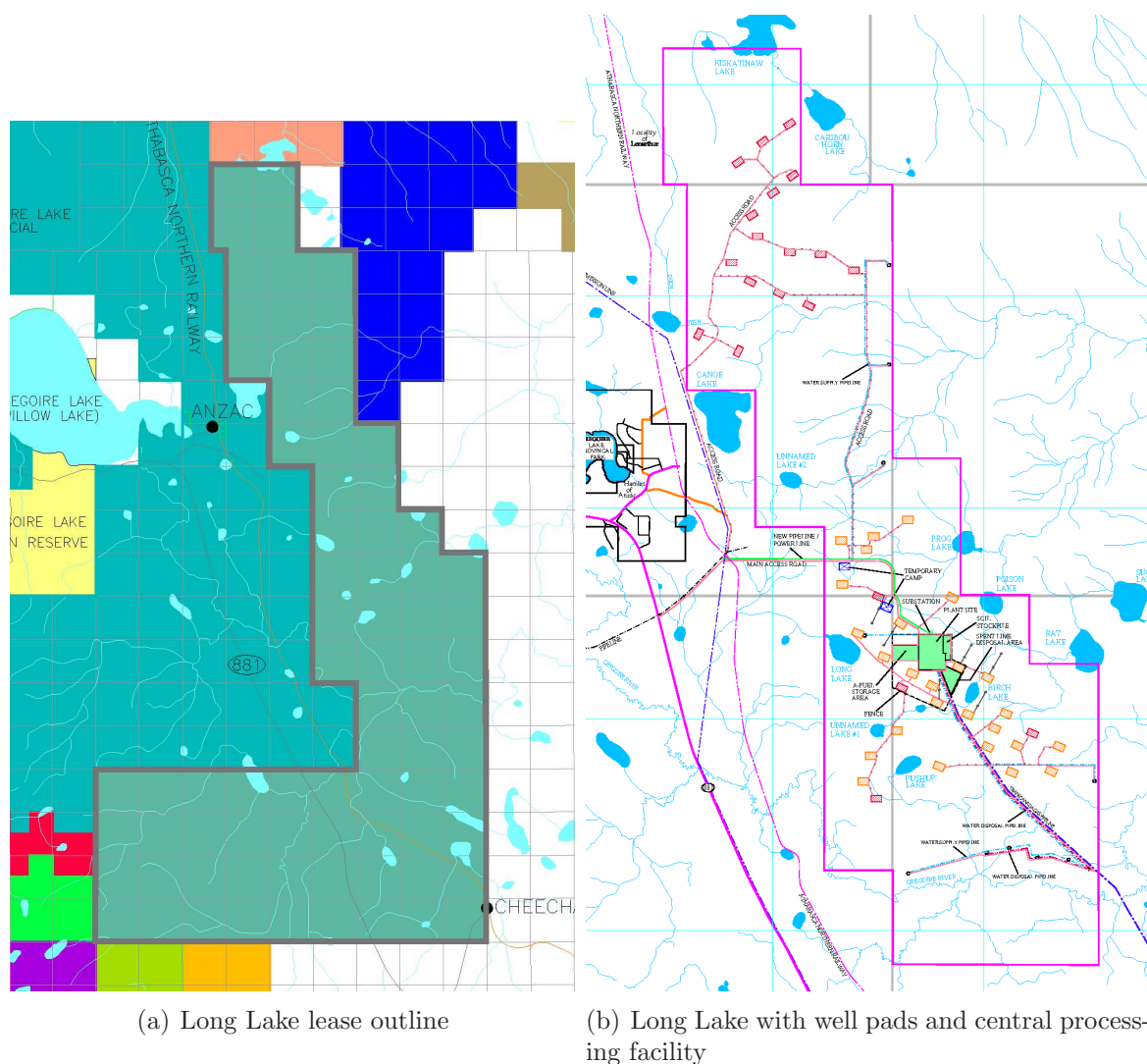
Figure 8.1: Oil sands leases in the Athabasca Region (Source: [59])

8.1.2 Steam Limitations

Heat losses limit the distance that steam can be piped, since high temperatures and pressures are needed to prevent the steam from condensing. The maximum radial distance steam can be piped while maintaining adequate temperatures and pressures needed for SAGD is around 15 km [6]. Because of these losses, the placement of the wellpads relative to the central processing facility is critical. Since SAGD projects are broken up into phases, the central processing facilities can be built between phases plots in order to produce the steam for more wellpads [61].

8.1.3 Location of Central Processing Facility

The central processing facility is the location steam production and bitumen processing. A given central processing facility is on the order of 1 km². For example, Devon Energy's Jackfish site, which produces 35,000 bbl/day, has a central operating facility measuring approximately 700 meters by 1000 meters [15]. Bitumen cannot easily be extracted from beneath the operating facility, so it is best if the central processing facility is not built over rich deposits. This obstacle must be weighed against the challenges in locating the



plant to minimize steam losses.

In Figure 8.3, the plot of the Jackfish facility, this tradeoff is illustrated. The lease itself is one of the more convenient plots offered by Canada. The plot is rectangular, which makes for easier well placement than oblong-shaped plots. The processing facility is at the very edge of the plot, likely in a place of low oil enrichment.

8.1.4 Transmission Lines

In the remote areas of Alberta, the accessibility of transmission lines varies greatly from lease to lease. In areas lacking a grid, transmission lines must be constructed, which can add a substantial amount to the capital cost. A transmission facilities owner must be hired to construct the power lines and the layout of the grid must be approved by the

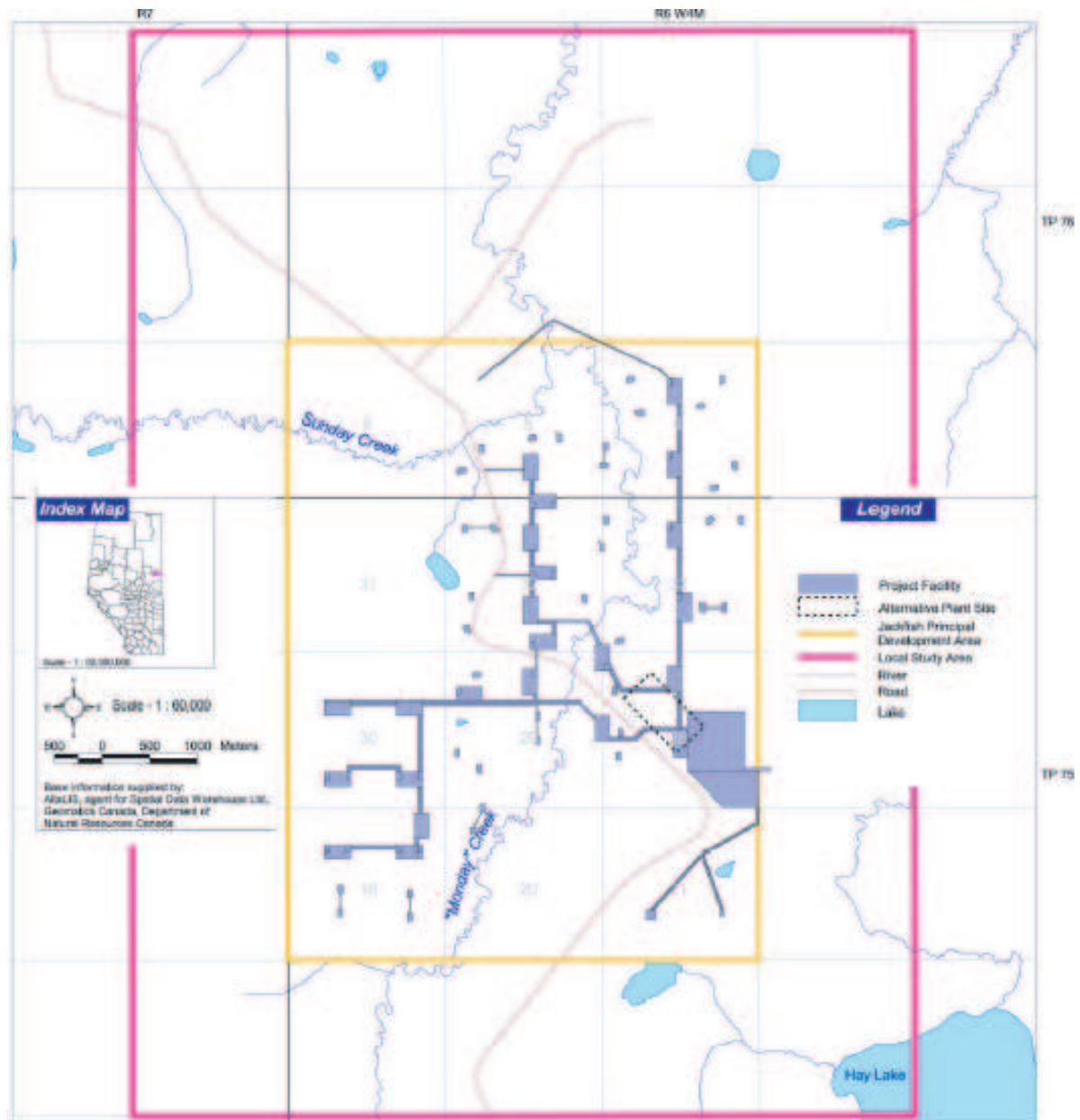


Figure 8.3: Layout of Jackfish with lease boundary, wellpads, and central processing facility (Source: [15])

Alberta Transmission Systems Administrator.

Most of the transmission lines in the more rural parts of Canada follow the highways. For ease of construction and accessibility, power lines erected for use by extraction facilities are run next to the access roads from the highway to the central facility. Figure 8.2 shows the transmission lines necessary for the Long Lake project, and outlines its wellpad structure. OPTI contracted to have a 5.8 km power line constructed to meet their needs.

8.1.5 Inclement Weather

The Alberta electricity grid can be unreliable due to harsh weather conditions. Storms and freezes are the cause of frequent power outages.

The extreme temperatures also make it difficult and expensive to operate and maintain the facility 365 days per year. In 2003, Western Oil Sands reported that progress on their oil sands facility had been seriously impeded as the result of harsh weather conditions [13]. Froth treatment tank damage, frozen pipelines, and damages caused by an electrical fire cost the company more than \$150 million in delays and repairs.

8.1.6 Personnel

The remoteness of the facilities make it difficult to hire full-time employees at reasonable wages. Maintenance crews, engineers, and administrators are difficult to find in rural Alberta. They have to be brought in from long distances, which raises their asking price. The cost of labor must be taken into account as well. A full cost analysis can be found in Chapter 9.

8.1.7 Diluent Shortages

The growth of the oil sands industry is expected to triple the diluent requirements over the next decade, leading to supply shortages. Some companies are already experiencing such shortages, and they are beginning to use synthetic crude oil as an alternative diluent to reduce the bitumen viscosity so that it can be shipped through pipelines [62]. This hinders the productivity potential of the industry.

8.1.8 Water Restrictions

Water to supply the reactor will need to be withdrawn from the Athabasca river, as this river provides a reliable and adequate source of fresh water and is located in relatively close proximity to the Athabasca oil sands [6]. Alberta's environmental regulations restrict the amount of water that may be diverted from this river for use at each oil sands facility to 14.2 m³/sec [6]. Since the water requirements for the reactor alone exceed this number, methods for reducing the amount of reactor makeup water are necessary. Two methods are water recycling and air cooling [6]. Water recycling involves allowing cooling water to recirculate [6] as opposed to only allowing it to be used once and then discarding it. In air cooling, cooling towers are used to allow the heat removed from the condenser to be

dissipated to the air [6]. Allowing this heat to dissipate into the air means that additional water for it to be dissipated into is not required. Cooling towers should work particularly well in northern Alberta due to the cold climate.

Substantial amounts of water are needed for the SAGD injection well, in addition to the water needs of the reactor. As calculated in section 5.2.1, a maximum of 0.72 m³/sec of water shall be required to make the steam required for the SAGD process. The water used for this process can be recycled, but makeup water is taken from the Athabasca River.

The water from the Athabasca River contains impurities, such as minerals, that will need to be removed before the water can be used by the facility [6]. A water treatment and purification plant will need to be constructed to ensure that any water entering the steam generators or other components of the reactor is of an acceptable purity [6].

A large reservoir will need to be constructed on the facility site, so that water can be stored in case of fire or other emergencies [6]. This reservoir will need to be heated during the winter months to prevent freezing [6].

8.2 Existing Facilities

This section provides a description of SAGD wellpads and key components of the central processing facility.

8.2.1 Well Pads

As explained in Chapter 5, the steam assisted gravity drainage (SAGD) process requires well pairs to be drilled into the underground oil sands deposits. Each pair consists of a steam injection well and a production well. The layout and design of these wells depends strongly on the piece of land, but key features can be discussed.

Each wellpad will typically include: wellhead collection piping, a group and test separator building, a manifold building, a blowdown pop tank, group flowlines, an electrical motor control center (MCC) and instrumentation building, and a soil stockpile area for upland wellpads only [15]. A typical layout for the Long Lake Project is shown in Figure 8.4.

The number and distribution of wellpads will depend on available drilling and production technologies, environmental issues and land characteristics. Each well pair produces bitumen in the order of 1,000 bbl/day, so a total production level of 100,000 bbl/day would initially require around 100 well pairs, drilled from 15-20 wellpads. Over the life

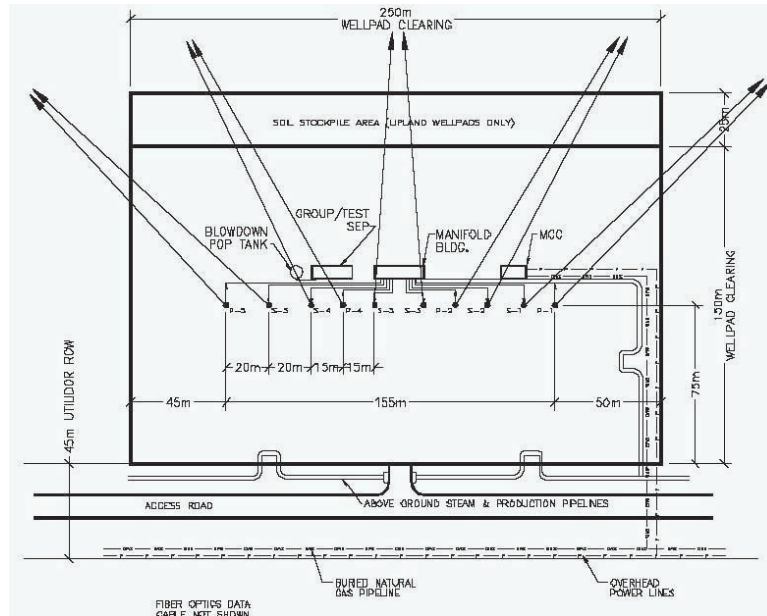


Figure 8.4: Typical SAGD wellpad layout (Source: [60])

of the project, additional well pairs will be drilled from other wellpads to compensate for the decline in production from existing well pairs.

Simulations for the Long Lake Project [60] show that, over time, less bitumen is recovered from a more heterogenous well. This is especially true for the last ten years of a well with a twenty year lifetime; after the first ten years there is a slow decline in production. At around year 14, a wind-down phase starts by stopping steam injection and keeping the reservoir pressure steady by gas injection. Figure 8.5 shows a typical simulated recovery rate performance of a well pair for that project.

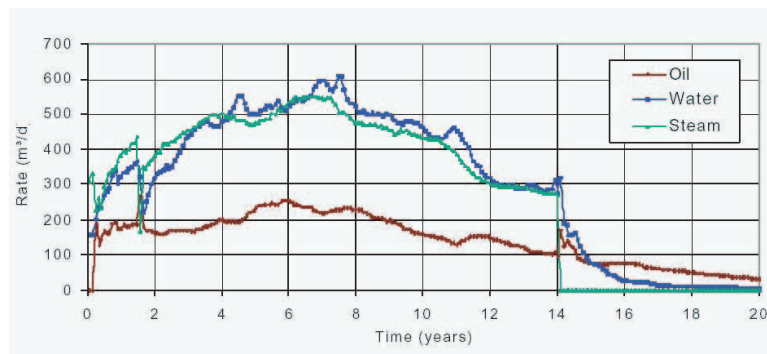


Figure 8.5: Recovery rate of a well pair for the Long Lake Project (Source: [60])

Usually, well drilling starts vertically and the inclination angle increases gradually until they are horizontal. The horizontal sections will measure 500-1000 meters, with a vertical separation of approximately 5 meters between the steam injection well above and its associated production well below [15]. The overall length of each well will depend on the depth of the horizontal sections and the planned well trajectory. Figures 8.6 and 8.7

illustrate the typical design of the wells.

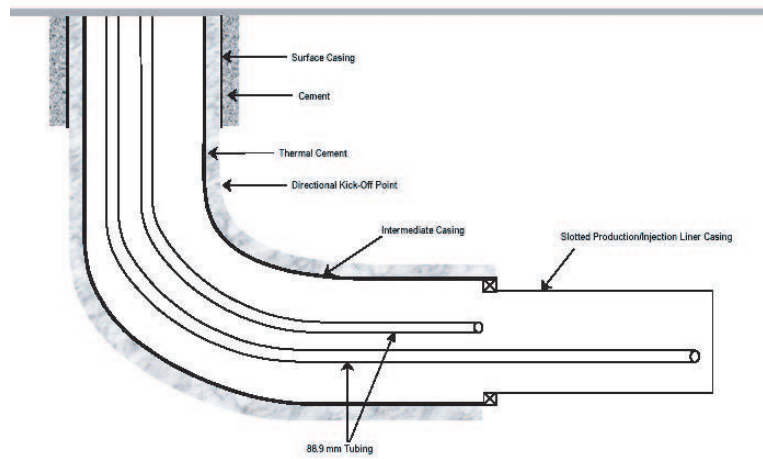


Figure 8.6: Injection well (Adapted: [15])

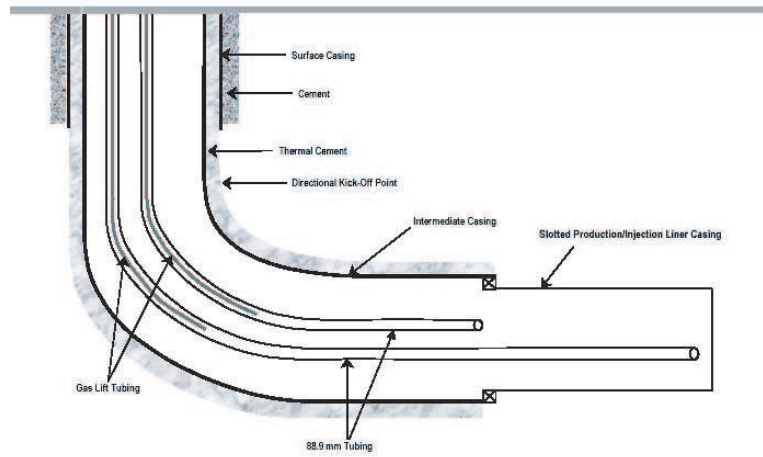


Figure 8.7: Production well (Adapted: [15])

There will be a spacing of 150-200 meters between well pairs in the horizontal section, meaning that the reservoir drainage area will be of the order of 750,000 square meters (75 hectares) per wellpad. This will depend on the number of well pairs per wellpad, the actual separation between the well pairs and the length of the horizontal sections. The cleared area for the wellpad itself will range from 30,000 to 50,000 square meters [60]. Figure 8.8 shows a typical single-wellpad drainage geometry.

8.2.2 Central Processing Facility

The central processing facility comprises five main systems: administrative offices, steam generation, bitumen processing, water treatment, and storage.

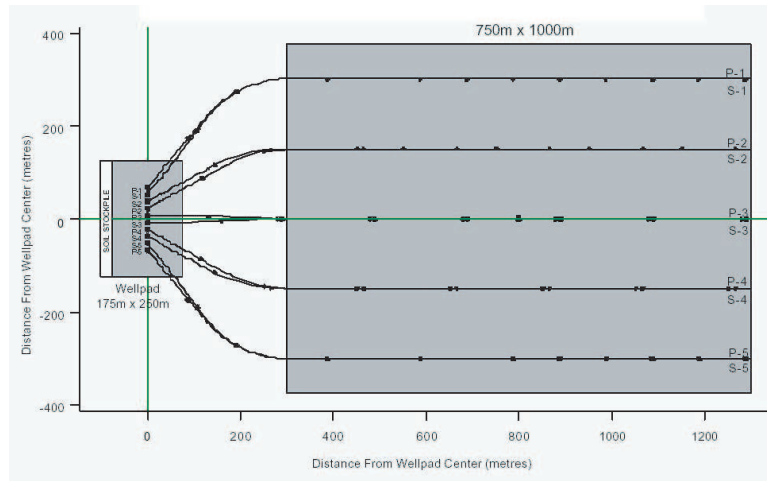


Figure 8.8: Typical single-wellpad drainage geometry (Adapted: [60])

The footprints for the Long Lake facility and the Jackfish project illustrate these aspects of the site and the following sections detail the significance of each. They can be seen in Figures 8.9 and 8.10.

The Jackfish central facility, relatively small compared with our reference plant of 100,000 bbl/day, covers just 600 meters by 600 meters. It is designed to produce as much as 35,000 bbl/day of bitumen. Long Lake, on the other hand, has a slightly smaller capacity, at 30,000 bbl/day.

Administration

First of all, the plant requires administrative buildings, offices for the engineers and maintenance crews, and a main entrance. The only restriction for this part of the facility is that it have road access. Of the four components, this is the simplest to locate and construct.

Steam Generation

The second component, which will require the most alteration with the nuclear proposal, is the steam generation system. For a system that produces only process heat, without a cogeneration plant to produce energy, this system is relatively simple. It includes several burners and steam generators. Water is heated to the appropriate temperature and then piped out to the wellpads. With a more complicated scenario, like the one at Long Lake, in which electricity is being produced in addition to the process heat, a cogeneration facility is built on site.

A plant such as Jackfish requires as many as six steam generators operating in parallel.

Each steam generator is outfitted with its own burner, which produces the process heat for the wells. Providing the water is a boiler feedwater storage tank. The steam that is produced by these boilers is piped directly out to the wellpads and into the injection wells.

The buildings required for this part of the plant are the steam generator building and the emergency generator building.

Bitumen Processing

After the steam has been piped into the injection well and out the production well, the mixture of bitumen, steam, and water is piped to the plant. When it reaches the central facility, it is first piped through a sequence of gravity separators, which separate the three ingredients from each other. The gas is removed through the top pipe, the bitumen through the middle, and the water through the bottom. The bitumen extracted through the separators has a water content of less than 10%. This stream is fed into a series of treaters that eliminate the remaining water, meeting the market specification of less than 0.5% by volume of water in the bitumen.

The part of the plant that performs these tasks includes these three separators, and, depending on the flow rate into the facility, more treaters. A facility the size of Jackfish can have as many as five treaters for processing the stream. Both the separators and the treaters are located in the bitumen processing area seen in the Jackfish footprint in Figure 8.10.

Water Treatment

The separators are sufficiently effective so that the oil content of the water is quite low; around 1000 mg/L. However, the water still needs to be treated to separate out more oil and gas before it can be recirculated through the steam generators. After it condenses, it is remixed with the produced water and run through the water treatment process. Residual oil in the feed water will damage the steam generators irreparably. The water treatment facility ensures that the water can be recycled safely.

The components involved in this process include a skim tank, an induced gas flotation vessel, an oil removal filter, and a de-oiled produced water tank. These processes are housed in the emulsion treatment building, the produced water de-oiling building, and the produced water treatment building.

Storage

In addition to the processing buildings, storage infrastructure is an essential component to the proper functioning of the central processing facility. A typical plant will include a bitumen and diluent storage tank, a produced water de-oiling tank, a boiler water feed tank, a sewage pond, a storm water runoff pond, and a topsoil conservation stockpile. The storage components of the central facility take up more space than any other component of the system.

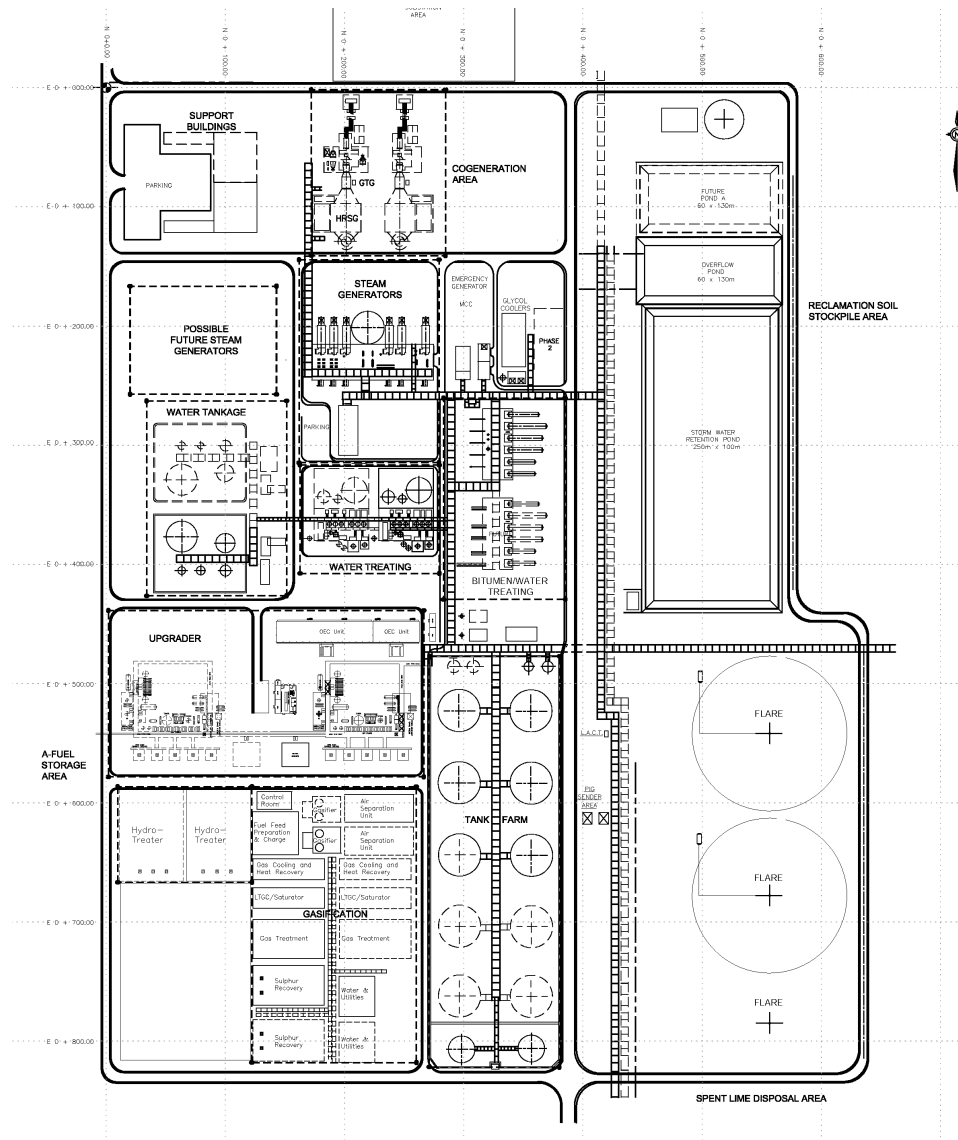


Figure 8.9: Footprint of Central Processing Facility for OPTI Canada Inc's Long Lake project (Source: [60])

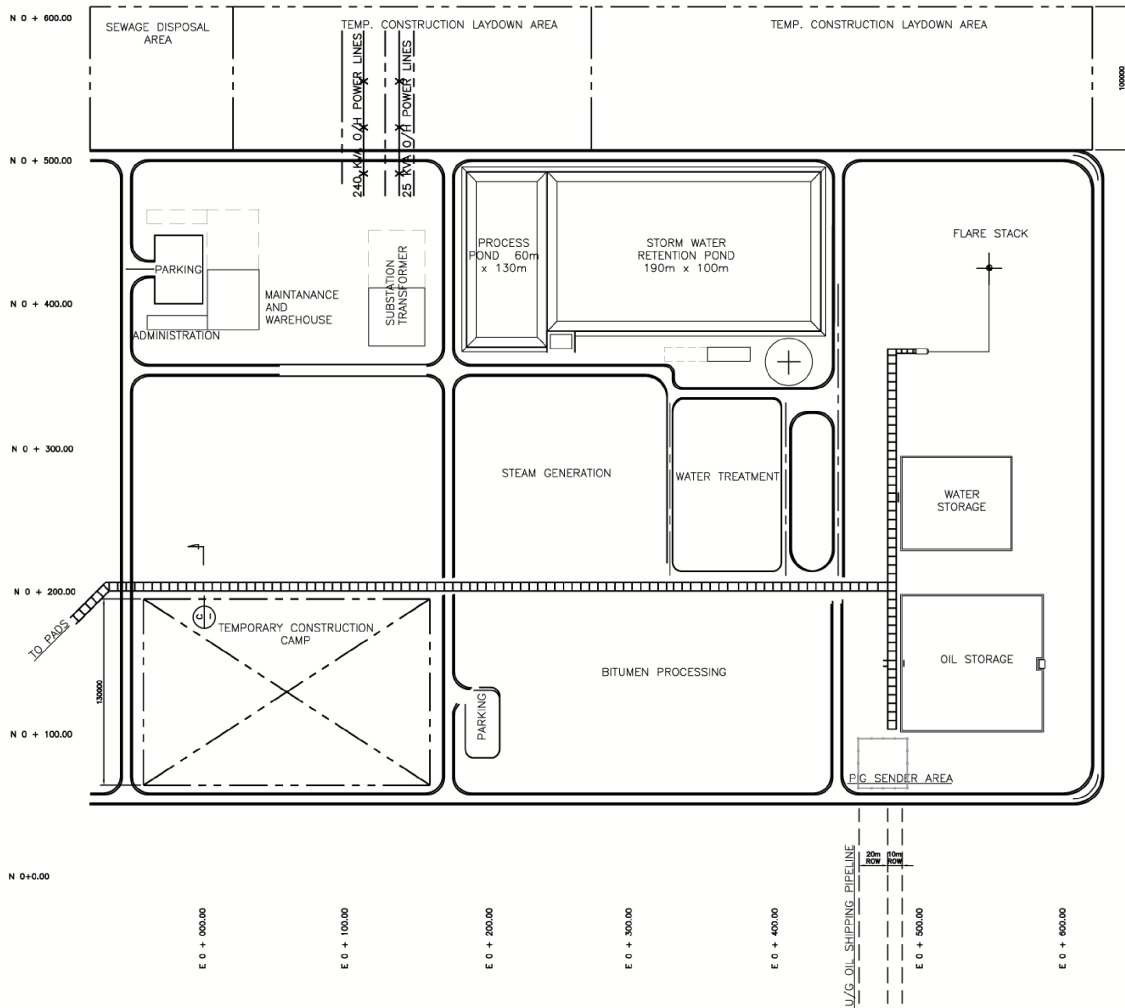


Figure 8.10: Footprint of Central Processing Facility for Devon Energy's Jackfish project (Source: [15])

8.3 Nuclear Reactor Land Area Requirements

8.3.1 Scenario 1

For Scenario 1, the nuclear plant would have one AP600 unit or four PBMRs. Since no electricity needs to be produced in this case, the plant would not require turbines, so the overall size would be smaller. The AP600 has dimensions $105\text{ m} \times 85\text{ m}$, taking an area of $8,925\text{ m}^2$; the PBMRs measure $103\text{ m} \times 57\text{ m}$, for a total area of $5,871\text{ m}^2$.

8.3.2 Scenario 2

Either one ACR-700 or five PBMRs would be used in Scenario 2. The former has dimensions $175\text{ m} \times 105\text{ m}$, or $18,375\text{ m}^2$; the latter configuration has not been prepared by

PBMR Ltd., but the dimensions can be estimated at 80 m \times 113 m, which corresponds to 9,040 m².

8.3.3 Scenario 3

For Scenario 3, the proposed options use two ACR-700, two AP600 units, or eight PBMRs. The twin ACRs would share systems, as outlined in Section A.1.7, and the plant would take 175 m \times 175 m, or 30,625 m²; the twin AP600s, on the other hand, would not share any systems, and would measure 175 m \times 190 m, covering 33,250 m²; the eight-PBMR plant's dimensions would be 103m \times 113 m, taking an area of 11,639 m².

Chapter 9

Economics

In this section, we will calculate total system costs for natural gas-fired facilities and nuclear options for the three different scenarios discussed earlier in Chapter 5. The first scenario uses a plant that only produces process heat for steam production on a SAGD project, and buys the electricity it requires to run the facility. Scenario two uses energy for the adequate production of both steam and electricity to run the oil sands facility. Scenario three includes the energy requirements for the production of steam, electricity, and compares the make-or-buy question for hydrogen for the upgrading of bitumen to syncrude. All costs in this section are in US dollars (US\$).

9.1 Natural Gas Cost

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 seemingly cheap and abundant. As the oil-sands production industry becomes 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. According to the Alberta Chamber of Resources, by 2030, the Alberta oil-sands industry may use up to sixty percent of the natural gas production of the MacKenzie Valley, CBM, and Western Canadian Sedimentary Basin combined.

The natural gas market over the past ten years is characterized by its volatile price and increasingly tightened supply and demand chain. Figure 9.1 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 \$13.50 mmBtu in October 2005.

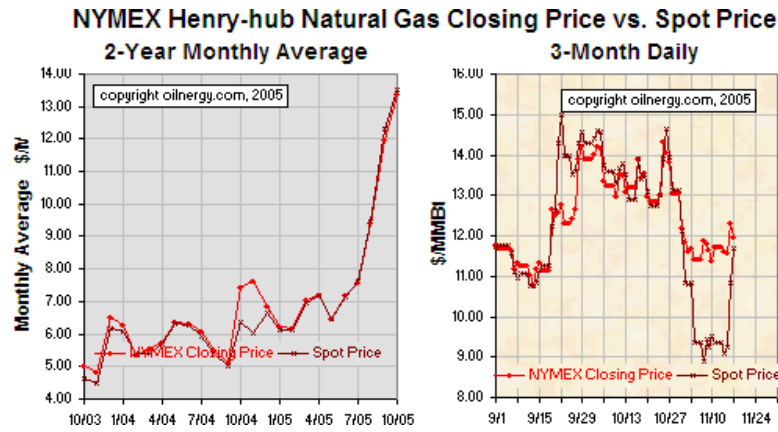


Figure 9.1: Natural Gas Prices (Source: [63])

The demand for oil has been steadily increasing, not only in North America, but also throughout the world [24]. 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. It is highly unlikely that the current rate of natural gas production will grow at a rate anywhere close to the growth in demand. The ultimate result will be increasingly volatile gas prices, rising at a rapid pace to satisfy market equilibrium.

There are four main types of costs that are important in the calculation of total system cost for a natural-gas fired facility:

- **Capital Cost:** The SAGD process uses natural gas-fired generators to produce steam for subsurface injection and in situ bitumen recovery. Steam can be produced using either standalone Once Through Steam Generators (OTSGs) or Heat Recovery Steam Generators (HRSGs) in a cogeneration configuration.
- **Operating & Maintenance Cost:** The O&M cost of the facility is used to measure the normal operating cost of the plant. This cost reflects all costs that are incurred to operate and maintain the plant. Included in this cost are salaries and benefits for the plant staff, parts, material and equipment costs for maintaining plant equipment, fees, insurance, overhead costs, and short-term contract services. Fuel cost is not included because it is calculated separately. An estimated O&M annual cost is about 10% of the capital costs [64].
- **Fuel Cost:** The market price of the natural gas needed to run the plant.
- **Decommissioning Cost:** Decommissioning is the process by which the liabilities associated with a retired facility are ultimately retired, secured or resolved. The process

can involve the removal of dangerous materials, program management, engineering and planning, and the interfacing with numerous regulatory authorities, public agencies, and other policy-setting organizations. The decommissioning/shutdown costs are estimated to be about 10% of the capital costs [64], same as with the O&M costs, to be incurred at the end of the life cycle of the natural gas facility.

This analysis thus takes into account the total cost of the steam production facility and the cost of hydrogen used in the bitumen upgrading process. It does not include the cost of the bitumen extraction, upgrading and syncrude processing, because these costs are assumed to be held constant regardless of type of steam production facility (i.e. natural gas vs. nuclear) and the scenario.

The next step to compare costs of each of the available options is to look three different unit costs:

- Cost of process heat: This is the cost of producing the process heat for the SAGD process as a function of the amount steam being heated.
- Cost of electricity: This is the cost of producing or buying the electricity requirements of the site.
- Cost of hydrogen: The addition of hydrogen to the bitumen is a costly step in the refining process, and this is the cost of buying the hydrogen or producing the hydrogen economically and partially upgrading on site.

9.1.1 Scenario 1 - Process Heat Only

A sample reference gas plant was designed by CERI, using 1 HRSG and 21 OTSGs for a 146,000 bpd operation and 100MW of electricity production [65]. Assuming a natural gas cogeneration facility for a 100,000 bpd operation, the capital cost is interpolated to be approximately \$120M [65].

The O&M and decommissioning costs is \$8M each [65].

To estimate the fuel costs, it is known that between 820 and 1260 MWth of energy is required to produce 100,000 bbl/day, which is converted to yearly energy consumption in mmBtu. Thus,

$$\left(1260 \frac{\text{MJ}}{\text{sec}}\right) \cdot \left(\frac{\text{mmBtu}}{1055 \text{ MJ}}\right) \cdot \left(84600 \frac{\text{sec}}{\text{day}}\right) \cdot \left(365 \frac{\text{day}}{\text{yr}}\right) \approx 3.688 \times 10^7 \frac{\text{mmBtu}}{\text{yr}} \quad (9.1)$$

A flat real natural gas price will be used for the base case economics, and this is conservatively estimated to be between 2003 projections of \$4.33/mmBtu [24] and current market price of \$10.50/mmBtu, at approximately \$8.00/mmBtu. As such,

$$\left(3.688 \times 10^7 \frac{\text{mmBtu}}{\text{yr}}\right) \cdot \left(\frac{\$8.00}{\text{mmBtu}}\right) \approx \frac{\$295 \text{ M}}{\text{yr}} \quad (9.2)$$

In this scenario, the 250MWe electricity requirement will be bought off the grid (under the assumption that access to the electricity grid in Alberta is readily available). The cost of electricity in Alberta is 6 Canadian cents/kWhr, according to the Alberta Energy Commission. Using a conversion rate of 0.85, it is equal to 5.1US cents/kWhr. Therefore, the additional cost of electricity for this scenario is:

$$\text{Annual Electricity Cost} = 250\text{MWe} \times \$0.051/\text{kWhr} \times 8760\text{hrs/yr} = \$111.7\text{M/yr} \quad (9.3)$$

The hydrogen required for the bitumen upgrading is assumed to have been bought for this scenario. This will be feasible under the assumption that there are hydrogen production plants nearby that can transport that can accommodate these needs. The unit price for hydrogen is then approximately \$2.50/kg of hydrogen [66]. A flow rate of 1253ft³/d is required per barrel of bitumen processed at the plant (from Section 5.4.1), thus the total annual cost of hydrogen is:

$$\begin{aligned} \text{Annual Hydrogen Cost}_{\text{new}} &= \left(1253 \frac{\text{ft}^3}{\text{day} \times \text{bbl}} \times (0.0000899 \frac{\text{g}}{\text{cm}^3}) \times (28316.85 \frac{\text{cm}^3}{\text{ft}^3})\right) \\ &\quad \times (365 \frac{\text{days}}{\text{year}}) \times (\$2.50/\text{kg}) \times (100,000 \frac{\text{bbl}}{\text{day}}) \\ &= \$291.1 \frac{\text{M}}{\text{yr}} \end{aligned} \quad (9.4)$$

To obtain the total costs, a discount rate of 10% is assumed over a 30-year lifespan of the natural gas-fired extraction facility. For analytical simplicity, it is assumed that all capital costs are incurred in the first year, and all decommissioning costs are incurred in the last year. The O&M and fuel costs are over the lifetime of the facility. Thus, the calculations for a net present value (NPV) at year 1 are:

$$\text{Capital Cost} = \$120 \text{ M} \quad (9.5)$$

$$\begin{aligned} \text{O \& M Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$8 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$75.4 \text{ M} \end{aligned} \quad (9.6)$$

$$\begin{aligned} \text{Fuel Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$295 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$2781 \text{ M} \end{aligned} \quad (9.7)$$

$$\text{Decommissioning} = \frac{\$8 \text{ M}}{(1 + 0.1)^{30}} = \$0.5 \text{ M} \quad (9.8)$$

$$\text{Total Cost of Process Heat} \approx \$2976.9 \text{ M} \quad (9.9)$$

$$\begin{aligned} \text{Total Cost of Electricity} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$111.7 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$1053 \text{ M} \end{aligned} \quad (9.10)$$

$$\begin{aligned} \text{Total Hydrogen Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$291.1 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$2744.2 \text{ M} \end{aligned} \quad (9.11)$$

9.1.2 Scenario 2 - Process Heat and Electricity

The capital, O&M, fuel and decommissioning costs for the primary plant remains the same as in Scenario 1, as does the cost of hydrogen being bought. However, the electricity needed for the facility will be produced, rather than bought off the grid, by a Combined Cycle Gas Turbine (CCGT) powered by additional steam generators. This system will cost an additional \$500/kW produced by the turbine [67], resulting in an annual cost of:

$$\text{Annual Electricity Cost} = 250\text{MWe} \times \$500/\text{kWe} \times 8760\text{hrs/yr} = \$125\text{M/yr} \quad (9.12)$$

Therefore, the total system cost over the 30 year lifetime of the facility is:

$$\text{Total Cost of Process Heat} \approx \$2976.9 \text{ M} \quad (9.13)$$

$$\begin{aligned} \text{Total Cost of Electricity} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$125 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$1178.4 \text{ M} \end{aligned} \quad (9.14)$$

$$\begin{aligned} \text{Total Hydrogen Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$291.1 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$2744.2 \text{ M} \end{aligned} \quad (9.15)$$

9.1.3 Scenario 3 - Process Heat, Electricity, and Hydrogen Production

The process heat and electricity costs for Scenario 3 remain the same as for Scenario 2. Hydrogen can be produced at the facility using Steam-Methane Reforming (SMR), a process described in detail in earlier sections. A flow rate of 1253ft³/d is required per barrel of bitumen processed at the plant, and at a cost of \$1.75/kg of H₂ [68], the total annual cost of hydrogen is:

$$\begin{aligned}
 \text{Annual Hydrogen Cost}_{new} &= (1253 \frac{\text{ft}^3}{\text{day} \times \text{bbl}} \times (0.0000899 \frac{\text{g}}{\text{cm}^3}) \times (28316.85 \frac{\text{cm}^3}{\text{ft}^3}) \\
 &\quad \times (365 \frac{\text{days}}{\text{year}}) \times (\$1.75/\text{kg}) \times (100,000 \frac{\text{bbl}}{\text{day}}) \\
 &= \$203.7 \frac{\text{M}}{\text{yr}}
 \end{aligned} \tag{9.16}$$

Therefore, the total system cost over the 30 year lifetime of the facility is:

$$\text{Total Cost of Process Heat} \approx \$2976.9\text{M} \tag{9.17}$$

$$\begin{aligned}
 \text{Total Cost of Electricity} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$125 \text{ M}}{(1 + 0.1)^t} \\
 &\approx \$1178.4 \text{ M}
 \end{aligned} \tag{9.18}$$

$$\begin{aligned}
 \text{Total Hydrogen Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$203.7 \text{ M}}{(1 + 0.1)^t} \\
 &\approx \$1920.3 \text{ M}
 \end{aligned} \tag{9.19}$$

The cost of hydrogen calculated here does not include cost of compliance with the Kyoto protocol, which will lead to a significant increase to the annual cost if Canada decides to adopt it.

9.1.4 Unit Costs and Cost Summary

To compare costs of natural gas-fired facilities and nuclear-powered facilities, unit costs can be used. The cost per unit steam (in \$/m³) incorporates the cost of process heat and electricity as a function of total steam produced for bitumen extraction. The hydrogen cost per unit bitumen (in \$/bbl) incorporates the cost of hydrogen production as a function of the daily bitumen production.

Type of Cost	Lifetime Cost (\$M)		
	Scenario 1	Scenario 2	Scenario 3
Process Heat	2976.9	2976.9	2976.9
Electricity	1053	1178.4	1178.4
Hydrogen	2744.2	2744.2	1920.3

Table 9.1: Natural Gas Cost Summary

	Scenario 1	Scenario 2	Scenario 3
Cost per Unit Steam (\$/m ³)	9.040	9.321	9.321
Hydrogen cost per Unit Bitumen (\$/bbl)	2.506	2.506	1.754

Table 9.2: Natural Gas Unit Cost

For calculating the cost per unit steam, we assume operation at 93% capacity with a steam oil ratio of 2.5:1 [65], a synthetic crude oil density of 0.159 m³/bbl, and a requirement of 1.055mmBtu of energy/barrel of crude oil [66]. Thus, we use the following formula to calculate total expected steam production for bitumen extraction over 30 years (note that the annual oil production was calculated in section 9.1.1):

$$\begin{aligned}
\text{Total Steam Production} &= \left(\frac{\text{Annual Oil Production} \times \text{Crude Oil Density} \times \text{SOR}}{\text{Operational Capacity}} \right) \times \text{Years of Operation} \\
&= 3.688 \times 10^7 \text{mmBtu/yr} \times \text{lb}/1.055\text{mmBtu} \times 0.159\text{m}^3/\text{bbl} \times 2.5 \times (1/93) \\
&= 1.486 \times 10^7 \text{m}^3/\text{yr}
\end{aligned} \tag{9.20}$$

$$\text{Total Steam Production} = (1.486 \times 10^7 \text{m}^3/\text{yr}) \times (30\text{yrs}) = 4.458 \times 10^8 \text{m}^3 \tag{9.21}$$

For calculating the hydrogen cost per unit bitumen, we use a production rate of 100,000 bpd. Table 9.1.4 shows the lifetime costs for each scenario, broken down by the type of cost, while Table 9.1.4 provides a summary of the unit costs.

9.1.5 Sensitivity of Cost to Natural Gas Prices

An important aspect of the cost calculations described above is to realize the sensitivity of our unit costs to any change in natural gas prices. As shown in Sections 9.1.1, 9.1.2 and 9.1.3, the fuel cost for a natural gas-fired facility is by far the largest overall cost. Our sensitivity analysis is conducted on Scenario 3 to include effects on all production costs.

$$\Delta P = 25\%; P_{new}$$

$$\begin{aligned}
&= 1.25 \cdot 8.00 \\
&= \frac{\$10.00}{\text{mmBtu}}
\end{aligned} \tag{9.22}$$

$$\begin{aligned}
\text{Fuel Cost}_{new} &= (3.688 \times 10^7) \cdot (\$10.00) \\
&\approx \frac{\$368.8 \text{ M}}{\text{yr}}
\end{aligned} \tag{9.23}$$

$$\begin{aligned}
\text{Total Fuel Cost}_{new} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} \\
&= \sum_{t=1}^{30} \frac{\$368.8 \text{ M}}{(1 + 0.1)^t} \\
&\approx \$3476.6 \text{ M}
\end{aligned} \tag{9.24}$$

$$\begin{aligned}
\text{Total Process Heat Cost}_{new} &= \$(96 + 90.5 + 3476.6 + 0.5) \text{ M} \\
&= \$3663.6 \text{ M}
\end{aligned} \tag{9.25}$$

$$\begin{aligned}
\text{Annual Hydrogen Cost}_{new} &= (1253 \frac{\text{ft}^3}{\text{day} \times \text{bbl}} \times (0.0000899 \frac{\text{g}}{\text{cm}^3}) \times (28316.85 \frac{\text{cm}^3}{\text{ft}^3}) \times \\
&\quad (365 \frac{\text{days}}{\text{year}}) \times (\$2.10/\text{kg}) \times (100,000 \frac{\text{bbl}}{\text{day}}) \\
&= \$244.5 \frac{\text{M}}{\text{yr}}
\end{aligned} \tag{9.26}$$

$$\begin{aligned}
\text{Total Hydrogen Cost}_{new} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} \\
&= \sum_{t=1}^{30} \frac{\$244.5 \text{ M}}{(1 + 0.1)^t} \approx \$2304.9 \text{ M}
\end{aligned} \tag{9.27}$$

$$\begin{aligned}
\Delta \text{Total System Cost} &= \frac{7146.9 - 6066.4}{6066.4} \\
&= 17.8\%
\end{aligned} \tag{9.28}$$

According to our calculations, a 25% increase in the natural gas price raises the unit price by 18%. These results match the conclusions drawn from several other studies, such as that at the Canadian Energy Research Institute (CERI), where researchers have compared the use of natural gas and nuclear energy to provide steam for in-situ oil recovery. In order to compare these two energies, several assumptions were made. In each case, a hypothetical plant was designed that produced 146,000 bbl/day of bitumen, and sold 100 MW of electricity to the Alberta Interconnected Electrical System. Natural gas prices were assumed to be \$3.50/mmBtu in the base year of the study. A sensitivity analysis was performed to compare the use of natural gas and nuclear fuel. The sensitivity calculations performed in the report show natural gas to be the most sensitive cost when considering both capital, operational, and electricity costs of comparable nuclear and natural gas facilities. Figure 9.2 shows a summary of the CERI study, where each cost factor is on the y-axis, with the change in the factor in brackets, and the volatility factor is graphed. [69]

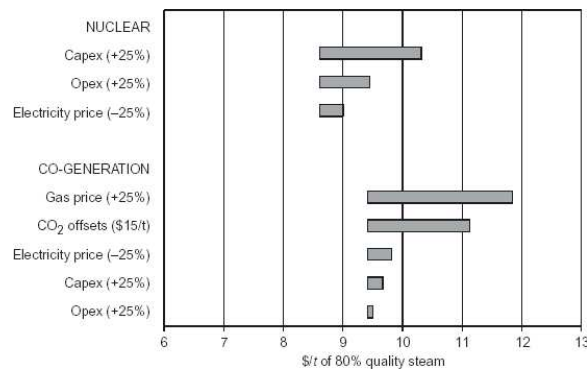


Figure 9.2: Study on Cost Volatility of Nuclear vs. Natural Gas Co-generation (Source:[69])

The CERI study only considered the cost of steam production, but similarly, the cost of hydrogen production is highly susceptible to natural gas prices (shown in Figure 9.3). This is true of both the 'make' side of the argument using a natural gas-fired plant as well as the 'buy' side since the private suppliers currently use natural gas to produce hydrogen.

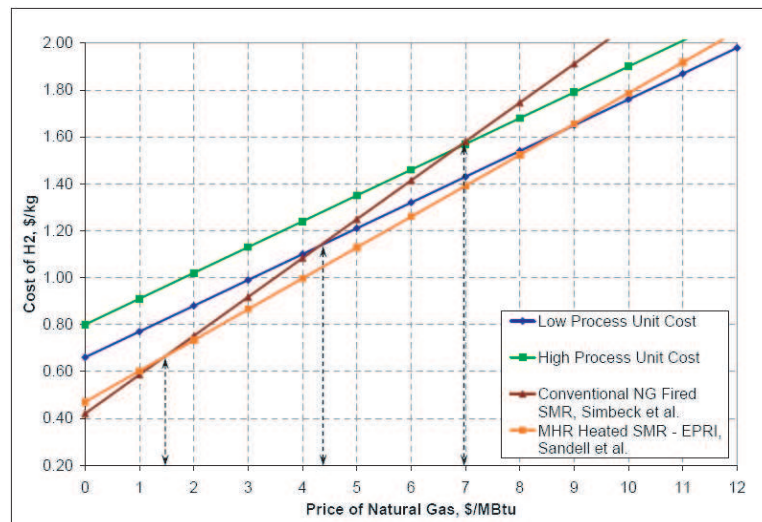


Figure 9.3: Cost of Hydrogen as a Function of Price of Natural Gas (Source: [70])

This is a significant effect, and given the volatility and upward trends in natural gas prices discussed in the earlier parts of this section, the uncertainty associated with the bottom-line cost of production can make the natural gas-fired facilities an economically infeasible project moving forward into the future.

This chapter has neglected the costs of the Kyoto protocol. The Kyoto treaty requires ambitious gas emission reduction rates which, if adopted by the Canadian government, could have a crippling effect on an energy-intensive economy dependent on natural gas facilities. As such, the costs of operating a natural gas-fired plant would be significantly higher than is anticipated by our calculations. The details of the impact of the protocol

on Canada's oil future is discussed in more depth in Section 4.5.2.

9.2 Nuclear Cost

With the current high market price of natural gas making gas-fired plants economically infeasible, the use of nuclear power has surfaced as a viable alternative. In this section, an economic analysis of the three reactors detailed in Chapter 6, the PBMR, AP600, and ACR-700, is conducted based on the various scenarios outlined in Chapter 5. Table 9.2 provides a quick summary of the costs associated with the nuclear options, some obtained from reliable outside sources (which are cited) and the rest extrapolated with best estimates.

	AP600 2 Unit Case	AP600 1 Unit Case	ACR-700 2 Unit Case	ACR-700 1 Unit Case	PBMR 1 Unit Case
Capital (\$USM)	1824.0	1012.3	2145	1190.5	206.3
Capital rate (\$US/kW)	1520 [71]	1687.2 [71]	1525.55 [72]	1693.4	1250 [73]
O&M (\$USM/year)	75.7	47.3	78.2	48.9	3.9
O&M rate (US mills/kWhe)	8 [74]	10	7.05 [72]	8.82	3.0 [73]
Decommission (\$USM)	567.6	354.8	156	102.7	46.8
Decommission rate (US mills/kWhe)	1 [74]	1.25	0.494 [72]	0.6175	0.6 [43]
Fuel rate (US mills/kWhe)	5 [74]	5	2.6 [72]	2.6	6.0 [73]
Operating Life (years)	60 [73]	60	30 [72]	30	60 [73]

Table 9.3: Costs Associated with the Nuclear Options, AP600 are 600 MWe/unit, 90% CF-IAEA, ACR-700 are 703 MWe/unit, 90% CF-CERI, PBMR are 165 MWe/unit, 90% CF-IAEA

Data for the rates of each cost category for the AP600 and ACR-700 twin units and the PBMR were obtained from outside sources. The ACR-700 data from CERI was originally in 2003 Canadian dollars, but the values were converted to US dollars using a currency exchange rate of 0.65 US\$ per C\$.

The data for the AP600 and ACR-700 single unit cases were then extrapolated, with the conservative assumption that capital rate costs would be 11% higher, and O&M

and decommissioning rate costs would be 25% higher since shared facilities and existing infrastructure affect the latter costs much more than they would the former. Fuel rate cost was assumed to stay the same for both the single unit and the twin unit. For the PBMR, it is assumed that costs for all additional units will be 90% of the first reactor built. The total cost for each category was calculated assuming a 90% capacity factor for all reactors [75]. All costs are for Nth-of-a-kind nuclear plants.

As discussed previously, each of the three scenarios being considered has different thermal energy requirements, from which we can estimate the number of each type of reactor needed to fulfill the requirements and thus calculate total system cost per reactor per scenario. The number of units of reactors required is shown in Table 9.2. In the following calculations, the requirement will be assumed to be the “high” number of units.

Scenario 1		
Reactor	Number of Units	
	Low	High
PBMR	3	4
ACR-700	1	1
AP600	1	1

Scenario 2		
Reactor	Number of Units	
	Low	High
PBMR	5	5
ACR-700	1	1
AP600	1	1

Scenario 3		
Reactor	Number of Units	
	Low	High
PBMR	7	8
ACR-700	2	2
AP600	2	2

Table 9.4: Number of units required in a given scenario

In the following scenarios, the fuel costs will be not be based on the number of reactors used but by the amount of heat being produced by the reactors instead. The net efficiency of the reactors to be used is listed in Table 9.2.

And, the formula used to calculate the fuel cost is:

	PBMR	ACR-700	AP600
Net Efficiency	40% [9-10]	37% [7-3]	31% [9-10]

Table 9.5: Net Efficiencies of Reactors

$$\begin{aligned}
\text{Annual Fuel Cost} = & \\
& \text{Thermal Energy Required} \times \text{Net Efficiency} \times \\
& \text{Capacity Factor} \times \text{Fuel Rate} \times 8760\text{Hours}
\end{aligned} \tag{9.29}$$

All calculations for reactors are based on a plant lifetime of 30 years to allow direct comparison with natural gas. It should be noted that for most reactor systems, the lifetime is actually much higher and therefore the nuclear facilities can still be operational at the end of the 30 years.

9.2.1 Scenario 1 - Process Heat Only

PBMR

The total costs of 4 PBMRs is obtained assuming full cost in Table 9.2 for the first reactor, and 90% cost for each subsequent reactor. All numbers obtained from outside sources include electricity generation facilities with the reactor costs. Thus, it is assumed that only 60% of the capital cost [76] is for the reactor structure itself.

$$\begin{aligned}
\text{Total Capital Cost} &= (\text{Cost of 1}^{st} \text{ Reactor} + 3 \times (.90) \times \\
&\quad \text{Cost of Additional Reactors}) \times 0.70 \\
&= (\$206.3\text{M} + (3 \times 0.90 \times \$206.3\text{M})) \times 0.70 \\
&= \$458\text{M}
\end{aligned} \tag{9.30}$$

$$\begin{aligned}
\text{Annual O\&M Cost} &= \text{Cost of 1}^{st} \text{ Reactor} + 3 \times (.90) \times \\
&\quad \text{Cost of Additional Reactors} \\
&= \$3.9\text{M} + (3 \times 0.90 \times \$3.9\text{M}) \\
&= \$14.5\text{M/yr}
\end{aligned} \tag{9.31}$$

$$\begin{aligned}
\text{Annual Fuel Cost} &= 1262\text{MWth} \times 0.40 \times 0.90 \times \\
&\quad 6.0\text{mills/kWhr} \times 8760\text{hrs/yr} \\
&= \$23.9\text{M/yr}
\end{aligned} \tag{9.32}$$

$$\begin{aligned}
\text{Total Decommissioning Cost} &= \text{Cost of 1}^{st} \text{ Reactor} + 3 \times (.90) \times \\
&\quad \text{Cost of Additional Reactors} \\
&= \$46.8\text{M} + (3 \times 0.90 \times \$46.8\text{M}) \\
&= \$173.2\text{M}
\end{aligned} \tag{9.33}$$

Therefore, the total cost of process heat over the 30 year lifetime of the plant is:

$$\text{Capital Cost} = \$458 \text{ M} \quad (9.34)$$

$$\begin{aligned} \text{O \& M Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$14.5 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$136.7 \text{ M} \end{aligned} \quad (9.35)$$

$$\begin{aligned} \text{Fuel Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$23.9 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$225.3 \text{ M} \end{aligned} \quad (9.36)$$

$$\text{Decommissioning} = \frac{\$173.2 \text{ M}}{(1 + 0.1)^{30}} = \$9.9 \text{ M} \quad (9.37)$$

$$\text{Total System Costs} \approx \$829.9 \text{ M} \quad (9.38)$$

The cost of buying electricity is the same as in Scenario 1 for natural gas, therefore:

$$\begin{aligned} \text{Annual Electricity Cost} &= 250\text{MWe} \times \$0.051/\text{kWhr} \times 8760\text{hrs/yr} \\ &= \$111.7\text{M/yr} \end{aligned} \quad (9.39)$$

$$\begin{aligned} \text{Total Cost of Electricity} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$111.7 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$1053 \text{ M} \end{aligned} \quad (9.40)$$

The cost of buying hydrogen for bitumen upgrading is the same as in Scenario 1 for natural gas, therefore:

$$\text{Total Hydrogen Cost} = \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$291.1 \text{ M}}{(1 + 0.1)^t} \approx \$2744.2 \text{ M} \quad (9.41)$$

ACR-700

The total capital cost of 1 ACR-700 is \$1190.5M, as shown in Table 9.2. Assuming only 60% of it is for the reactor structure [76], as before, the total capital cost is \$714.3M.

The annual O&M cost of 1 ACR-700 is \$48.9M/yr, as shown in Table 9.2.

$$\text{Annual Fuel Cost} = 1262\text{MWth} \times 0.37 \times 0.90 \times$$

$$\begin{aligned}
& 2.6\text{mills/kWhr} \times 8760\text{hrs/yr} \\
& = \$9.6\text{M/yr}
\end{aligned} \tag{9.42}$$

The total decommissioning cost of 1 ACR-700 is \$102.7M, as shown in Table 9.2.

Therefore, the total cost of process heat over the 30 year lifetime of the plant is:

$$\text{Capital Cost} = \$714.3 \text{ M} \tag{9.43}$$

$$\begin{aligned}
\text{O \& M Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$48.9 \text{ M}}{(1 + 0.1)^t} \\
&\approx \$461 \text{ M}
\end{aligned} \tag{9.44}$$

$$\begin{aligned}
\text{Fuel Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$9.6 \text{ M}}{(1 + 0.1)^t} \\
&\approx \$90.5 \text{ M}
\end{aligned} \tag{9.45}$$

$$\text{Decommissioning} = \frac{\$102.7 \text{ M}}{(1 + 0.1)^{30}} = \$5.9 \text{ M} \tag{9.46}$$

$$\text{Total Cost of Process Heat} \approx \$1271.7\text{M} \tag{9.47}$$

The cost of buying electricity is the same as in Scenario 1 for natural gas, therefore:

$$\begin{aligned}
\text{Annual Electricity Cost} &= 250\text{MWe} \times \$0.051/\text{kWhr} \times 8760\text{hrs/yr} \\
&= \$111.7\text{M/yr}
\end{aligned} \tag{9.48}$$

$$\begin{aligned}
\text{Total Cost of Electricity} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$111.7 \text{ M}}{(1 + 0.1)^t} \\
&\approx \$1053 \text{ M}
\end{aligned} \tag{9.49}$$

The cost of buying hydrogen for bitumen upgrading is the same as in scenario 1 for natural gas, therefore:

$$\text{Total Hydrogen Cost} = \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$291.1 \text{ M}}{(1 + 0.1)^t} \approx \$2744.2 \text{ M} \tag{9.50}$$

AP600

The total capital cost of 1 AP600 is \$1012.3M, as shown in Table 9.2. Assuming only 60% of it is for the reactor structure [76], as before, the total capital cost is \$607.4M.

The annual O&M cost of 1 AP600 is \$47.3M/yr, as shown in Table 9.2.

$$\begin{aligned}\text{Annual Fuel Cost} &= 1262\text{MWth} \times 0.31 \times 0.90 \times 5.0\text{mills/kWhr} \times 8760\text{hrs/yr} \\ &= \$15.4\text{M/yr}\end{aligned}\tag{9.51}$$

The total decommissioning cost of 1 AP600 is \$354.8M, as shown in Table 9.2.

Therefore, the total cost of process heat over the 30 year lifetime of the plant is:

$$\text{Capital Cost} = \$607.4 \text{ M} \tag{9.52}$$

$$\begin{aligned}\text{O \& M Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$47.3 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$445.9 \text{ M}\end{aligned}\tag{9.53}$$

$$\begin{aligned}\text{Fuel Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$15.4 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$145.2 \text{ M}\end{aligned}\tag{9.54}$$

$$\text{Decommissioning} = \frac{\$354.8 \text{ M}}{(1 + 0.1)^{30}} = \$20.3 \text{ M} \tag{9.55}$$

$$\text{Total Cost of Process Heat} \approx \$1218.8\text{M} \tag{9.56}$$

The cost of buying electricity is the same as in Scenario 1 for natural gas, therefore:

$$\begin{aligned}\text{Annual Electricity Cost} &= 250\text{MWe} \times \$0.051/\text{kWhr} \times 8760\text{hrs/yr} \\ &= \$111.7\text{M/yr}\end{aligned}\tag{9.57}$$

$$\begin{aligned}\text{Total Cost of Electricity} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$111.7 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$1053 \text{ M}\end{aligned}\tag{9.58}$$

The cost of buying hydrogen for bitumen upgrading is the same as in Scenario 1 for natural gas, therefore:

$$\begin{aligned}
\text{Total Hydrogen Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$291.1 \text{ M}}{(1 + 0.1)^t} \\
&\approx \$2744.2 \text{ M}
\end{aligned} \tag{9.59}$$

9.2.2 Scenario 2 - Process Heat and Electricity

PBMR

5 PBMRs are used in this Scenario, with 2 of them capable of producing electricity (i.e. full capital costs), and 3 of them producing only process heat (i.e. 60% capital cost). Assuming full cost of the first reactor and 90% costs for the subsequent reactors:

$$\begin{aligned}
\text{Total Capital Cost} &= \text{Cost of 1}^{st} \text{ Reactor} + 4 \times (.90) \times \\
&\quad \text{Cost of Additional Reactors} \\
&= (\$206.3\text{M} + (2 \times 0.90 \times \$206.3\text{M})) \times \\
&\quad 0.60 + (2 \times 0.90 \times \$206.3\text{M}) \\
&= \$717.9\text{M}
\end{aligned} \tag{9.60}$$

$$\begin{aligned}
\text{Annual O\&M Cost} &= \text{Cost of 1}^{st} \text{ Reactor} + 4 \times (.90) \times \\
&\quad \text{Cost of Additional Reactors} \\
&= \$3.9\text{M} + (4 \times 0.90 \times \$3.9\text{M}) \\
&= \$18\text{M/yr}
\end{aligned} \tag{9.61}$$

$$\begin{aligned}
\text{Annual Fuel Cost} &= 1600\text{MWth} \times 0.40 \times 0.90 \times \\
&\quad 6.0\text{mills/kWhr} \times 8760\text{hrs/yr} \\
&= \$30.3\text{M/yr}
\end{aligned} \tag{9.62}$$

$$\begin{aligned}
\text{Total Decommissioning Cost} &= \text{Cost of 1}^{st} \text{ Reactor} + 4 \times (.90) \times \\
&\quad \text{Cost of Additional Reactors} \\
&= \$46.8\text{M} + (4 \times 0.90 \times \$46.8\text{M}) \\
&= \$215.3\text{M}
\end{aligned} \tag{9.63}$$

The total cost for process heat and buying hydrogen will be the same as in Scenario 1, with the residual costs being the total cost of electricity. Thus, for the 30 year lifetime of the plant:

$$\text{Capital Cost} = \$717.9 \text{ M} \quad (9.64)$$

$$\begin{aligned} \text{O \& M Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$18 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$169.7 \text{ M} \end{aligned} \quad (9.65)$$

$$\begin{aligned} \text{Fuel Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$30.3 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$285.6 \text{ M} \end{aligned} \quad (9.66)$$

$$\text{Decommissioning} = \frac{\$215.3 \text{ M}}{(1 + 0.1)^{30}} = \$12.4 \text{ M} \quad (9.67)$$

$$\text{Total System Costs} \approx \$1185.6 \text{ M} \quad (9.68)$$

$$\text{Total Cost of Process Heat} = \$669.6 \text{ M} \quad (9.69)$$

$$\text{Total Cost of Electricity} = (\$1185.6 \text{ M} - \$829.9 \text{ M}) = \$355.7 \text{ M} \quad (9.70)$$

$$\text{Total Hydrogen Cost} = \$2744.2 \text{ M} \quad (9.71)$$

ACR-700

The total capital cost of 1 ACR-700 with electricity-producing capabilities is \$1190.5M.

The annual O&M cost of 1 ACR-700 is \$48.9M/yr, as shown in Table 9.2.

$$\begin{aligned} \text{Annual Fuel Cost} &= 1600 \text{ MWth} \times 0.37 \times 0.90 \times \\ &\quad 2.6 \text{ mills/kWhr} \times 8760 \text{ hrs/yr} \\ &= \$12.1 \text{ M/yr} \end{aligned} \quad (9.72)$$

The total decommissioning cost of 1 ACR-700 is \$102.7M, as shown in Table 9.2.

The total cost for process heat will be the same as in Scenario 1, with the residual costs being the total cost of electricity. Thus, over the 30 year lifetime of the plant:

$$\text{Capital Cost} = \$1190.5 \text{ M} \quad (9.73)$$

$$\begin{aligned} \text{O \& M Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$48.9 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$461 \text{ M} \end{aligned} \quad (9.74)$$

$$\text{Fuel Cost} = \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$12.1 \text{ M}}{(1 + 0.1)^t}$$

$$\approx \$114.1 \text{ M} \quad (9.75)$$

$$\text{Decommissioning} = \frac{\$102.7 \text{ M}}{(1 + 0.1)^{30}} = \$5.9 \text{ M} \quad (9.76)$$

$$\text{Total System Cost} \approx \$1771.5\text{M} \quad (9.77)$$

$$\text{Total Cost of Process Heat} \approx \$1271.7\text{M} \quad (9.78)$$

$$\text{Total Cost of Electricity} = (\$1771.5\text{M} - \$1271.7\text{M}) = \$499.8\text{M} \quad (9.79)$$

$$\text{Total Hydrogen Cost} = \$2744.2\text{M} \quad (9.80)$$

AP600

The total capital cost of 1 AP600 with electricity-producing capabilities is \$1012.3M.

The annual O&M cost of 1 AP600 is \$47.3M/yr, as shown in Table 9.2.

$$\begin{aligned} \text{Annual Fuel Cost} &= 1600\text{MWth} \times 0.31 \times 0.90 \times \\ &\quad 5.0\text{mills/kWhr} \times 8760\text{hrs/yr} \\ &= \$19.6\text{M/yr} \end{aligned} \quad (9.81)$$

The total decommissioning cost of 1 AP600 is \$354.8M, as shown in Table 9.2.

The total cost for process heat will be the same as in Scenario 1, with the residual costs being the total cost of electricity. Thus, over the 30 year lifetime of the plant:

$$\text{Capital Cost} = \$1012.3 \text{ M} \quad (9.82)$$

$$\begin{aligned} \text{O \& M Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$47.3 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$445.9 \text{ M} \end{aligned} \quad (9.83)$$

$$\begin{aligned} \text{Fuel Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^N \frac{\$19.6 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$184.8 \text{ M} \end{aligned} \quad (9.84)$$

$$\text{Decommissioning} = \frac{\$354.8 \text{ M}}{(1 + 0.1)^{30}} = \$20.3 \text{ M} \quad (9.85)$$

$$\text{Total Cost of Process Heat} \approx \$1663.3\text{M} \quad (9.86)$$

$$\text{Total Cost of Process Heat} \approx \$1218.8\text{M} \quad (9.87)$$

$$\text{Total Cost of Electricity} = (\$1663.3\text{M} - \$1218.8\text{M}) = \$444.5\text{M} \quad (9.88)$$

$$\text{Total Hydrogen Cost} = \$2744.2\text{M} \quad (9.89)$$

9.2.3 Scenario 3 - Process Heat, Electricity and Hydrogen Production

There are two distinct types of costs associated with the production of hydrogen. The first is that of generating the electricity and steam required for the process to run, which is calculated for each reactor below. The second is the capital cost of the High Temperature Steam Electrolysis (HTSE) plant itself - the cost is interpolated from existing data to be approximately \$80M/yr [70] for the size of the plant needed.

PBMR

8 PBMRs are used in this scenario, 5 of them set up as in Scenario 2, and the additional 3 PBMRs capable of producing electricity, and thus having full capital costs. Assuming full cost for the first reactor and 90% cost for each subsequent reactor:

$$\begin{aligned}
 \text{Total Capital Cost} &= \text{Cost of 1}^{st} \text{ Reactor} + 7 \times (.90) \times \\
 &\quad \text{Cost of Additional Reactors} \\
 &= (\$206.3\text{M} + (2 \times 0.90 \times \$206.3\text{M})) \times \\
 &\quad 0.60 + (5 \times 0.90 \times \$206.3\text{M}) \\
 &= \$1274.9\text{M} \tag{9.90}
 \end{aligned}$$

$$\begin{aligned}
 \text{Annual O\&M Cost} &= \text{Cost of 1}^{st} \text{ Reactor} + 7 \times (.90) \times \\
 &\quad \text{Cost of Additional Reactors} \\
 &= \$3.9\text{M} + (7 \times 0.90 \times \$3.9\text{M}) \\
 &= \$28.5\text{M/yr} \tag{9.91}
 \end{aligned}$$

$$\begin{aligned}
 \text{Annual Fuel Cost} &= 2800\text{MWth} \times 0.40 \times 0.90 \times \\
 &\quad 6.0\text{mills/kWhr} \times 8760\text{hrs/yr} \\
 &= \$53\text{M/yr} \tag{9.92}
 \end{aligned}$$

$$\begin{aligned}
 \text{Total Decommissioning Cost} &= \text{Cost of 1}^{st} \text{ Reactor} + 7 \times (.90) \times \\
 &\quad \text{Cost of Additional Reactors} \\
 &= \$46.8\text{M} + (7 \times 0.90 \times \$46.8\text{M}) \\
 &= \$341.7\text{M} \tag{9.93}
 \end{aligned}$$

The total cost for process heat and electricity will be the same as in Scenario 2, with the residual costs being the total cost of producing hydrogen. Thus, over the 30 year lifetime of the plant:

$$\text{Capital Cost} = \$1274.9 \text{ M} \quad (9.94)$$

$$\begin{aligned} \text{O \& M Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$28.5 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$268.7 \text{ M} \end{aligned} \quad (9.95)$$

$$\begin{aligned} \text{Fuel Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$53 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$499.6 \text{ M} \end{aligned} \quad (9.96)$$

$$\text{Decommissioning} = \frac{\$341.7 \text{ M}}{(1 + 0.1)^{30}} = \$19.6 \text{ M} \quad (9.97)$$

$$\begin{aligned} \text{HTSE Plant Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$80 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$754.2 \text{ M} \end{aligned} \quad (9.98)$$

$$\text{Total System Costs} \approx \$2817 \text{ M} \quad (9.99)$$

$$\text{Total Cost of Process Heat} = \$669.6\text{M} \quad (9.100)$$

$$\text{Total Cost of Electricity} = (\$1185.6\text{M} - \$829.9\text{M}) = \$355.7\text{M} \quad (9.101)$$

$$\text{Total Hydrogen Cost} = (\$2817 - \$669.6 - \$355.7) = \$1791.7\text{M} \quad (9.102)$$

ACR-700

The total cost of twin-unit ACR-700 is \$2145M, as shown in Table 9.2.

The annual O&M cost of twin-unit ACR-700 is \$78.2M/yr, as shown in Table 9.2.

$$\begin{aligned} \text{Annual Fuel Cost} &= 2800\text{MWth} \times 0.37 \times 0.90 \times \\ &\quad 2.6\text{mills/kWhr} \times 8760\text{hrs/yr} \\ &= \$21.2\text{M/yr} \end{aligned} \quad (9.103)$$

The total decommissioning cost of twin-unit ACR-700 is \$156M, as shown in Table 9.2.

The total cost for process heat and electricity will be the same as in Scenario 2, with the residual costs being the total cost of producing hydrogen. Thus, over the 30 year lifetime of the plant:

$$\text{Capital Cost} = \$2145 \text{ M} \quad (9.104)$$

$$\begin{aligned}\text{O \& M Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$78.2 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$737.2 \text{ M}\end{aligned}\quad (9.105)$$

$$\begin{aligned}\text{Fuel Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$21.2 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$199.8 \text{ M}\end{aligned}\quad (9.106)$$

$$\text{Decommissioning} = \frac{\$156 \text{ M}}{(1 + 0.1)^{30}} = \$17.4 \text{ M} \quad (9.107)$$

$$\begin{aligned}\text{HTSE Plant Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$80 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$754.2 \text{ M}\end{aligned}\quad (9.108)$$

$$\text{Total System Costs} \approx \$3853.6 \text{ M} \quad (9.109)$$

$$\text{Total Cost of Process Heat} = \$1271.7\text{M} \quad (9.110)$$

$$\text{Total Cost of Electricity} = \$499.8\text{M} \quad (9.111)$$

$$\text{Total Hydrogen Cost} = (\$3853.6 - \$1271.7 - \$499.8) = \$2082.1\text{M} \quad (9.112)$$

AP600

The total cost of twin-unit AP600 is \$1824M, as shown in Table 9.2.

The annual O&M cost of twin-unit AP600 is \$75.7M/yr, as shown in Table 9.2.

$$\begin{aligned}\text{Annual Fuel Cost} &= 2800\text{MWth} \times 0.31 \times 0.90 \times \\ &\quad 5.0\text{mills/kWhr} \times 8760\text{hrs/yr} \\ &= \$34.2\text{M/yr}\end{aligned}\quad (9.113)$$

The total decommissioning cost of twin-unit AP600 is \$567.6M, as shown in Table 9.2.

The total cost for process heat and electricity will be the same as in Scenario 2, with the residual costs being the total cost of producing hydrogen. Thus, over the 30 year lifetime of the plant:

$$\text{Capital Cost} = \$1824 \text{ M} \quad (9.114)$$

$$\begin{aligned}\text{O \& M Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$75.7 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$713.6 \text{ M}\end{aligned}\quad (9.115)$$

$$\begin{aligned}\text{Fuel Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$34.2 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$322.4 \text{ M}\end{aligned}\quad (9.116)$$

$$\text{Decommissioning} = \frac{\$567.6 \text{ M}}{(1 + 0.1)^{30}} = \$32.5 \text{ M} \quad (9.117)$$

$$\begin{aligned}\text{HTSE Plant Cost} &= \sum_{t=1}^N \frac{\text{Annual Cost}}{(1 + \text{Discount Rate})^t} = \sum_{t=1}^{30} \frac{\$80 \text{ M}}{(1 + 0.1)^t} \\ &\approx \$754.2 \text{ M}\end{aligned}\quad (9.118)$$

$$\text{Total System Costs} \approx \$3646.7 \text{ M} \quad (9.119)$$

$$\text{Total Cost of Process Heat} = \$1218.8 \text{ M} \quad (9.120)$$

$$\text{Total Cost of Electricity} = (\$1663.3 \text{ M} - \$1218.8 \text{ M}) = \$444.5 \text{ M} \quad (9.121)$$

$$\text{Total Hydrogen Cost} = (\$3646.7 - \$1218.8 - \$444.5) = \$1983.4 \text{ M} \quad (9.122)$$

9.2.4 Unit Costs and Cost Summary

As in section 9.1.4, cost per unit steam for the process heat and electricity, and hydrogen cost per unit bitumen for the cost of hydrogen production, will be used to compare costs, both between nuclear technologies and with natural gas.

For calculating the cost per unit steam, we assume operation at 93% capacity with a steam to oil ratio (SOR) of 2.5:1 [65], a synthetic crude oil density of 0.159 m³/bbl, and a requirement of 1.055 mmBtu of energy/barrel of crude oil [65]. Thus, we use the following formula to calculate total expected steam production for bitumen extraction over 30 years (note that the annual oil production was calculated in section 9.1.1):

$$\begin{aligned}\text{Total Steam Production} &= \left(\frac{\text{Annual Oil Production} \times \text{Crude Oil Density} \times \text{Steam-Oil Ratio}}{\text{Operational Capacity}} \right) \\ &\quad \times \text{Years of Operation}\end{aligned}\quad (9.123)$$

$$\begin{aligned}&= 3.688 \times 10^7 \text{ mmBtu/yr} \times \text{lb}/1.055 \text{ mmBtu} \times \\ &\quad 0.159 \text{ m}^3/\text{bbl} \times 2.5 \times (1/93) \\ &= 1.486 \times 10^7 \text{ m}^3/\text{yr}\end{aligned}\quad (9.124)$$

$$\begin{aligned}\text{Total Steam Production} &= (1.486 \times 10^7 \text{ m}^3/\text{yr}) \times (30 \text{ yrs}) \\ &= 4.458 \times 10^8 \text{ m}^3\end{aligned}\quad (9.125)$$

		Lifetime Costs (\$M)		
		PBMR	ACR-700	AP600
Scenario 1	Process Heat	829.9	1271.7	1218.8
	Electricity	1053	1053	1053
	<i>Total</i>	<i>1882.9</i>	<i>2324.7</i>	<i>2271.8</i>
Scenario 2	Process Heat	829.9	1271.7	1218.8
	Electricity	355.7	499.8	444.5
	<i>Total</i>	<i>1185.6</i>	<i>1771.5</i>	<i>1663.3</i>
Scenario 3	Process Heat	829.9	1271.7	1218.8
	Electricity	355.7	499.8	444.5
	Buy Hydrogen	2744.2	2744.2	2744.2
	Make Hydrogen	1791.7	2082.1	1983.4
	<i>Total</i>	<i>2977.3</i>	<i>3853.6</i>	<i>3646.7</i>

Table 9.6: Nuclear Cost Summary

		PBMR	ACR-700	AP600
Scenario 1	Cost per Unit Steam (\$/m ³)	4.224	5.215	5.096
Scenario 2	Cost per Unit Steam (\$/m ³)	2.660	3.974	3.731
Scenario 3	Cost per Unit Steam (\$/m ³)	2.660	3.974	3.731
Hydrogen Bought	Cost per Unit Bitumen (\$/bbl)	2.506	2.506	2.506
Hydrogen Produced	Cost per Unit Bitumen (\$/bbl)	1.636	1.901	1.811

Table 9.7: Nuclear Unit Costs

For calculating the hydrogen cost per unit bitumen, we use a production rate of 100,000 bpd. Table 9.2.4 shows the lifetime costs for each scenario, broken down by the type of cost, while Table 9.2.4 provides a summary of the unit costs.

9.2.5 Sensitivity of Cost to Nuclear Capital Cost

The largest percentage of the cost for nuclear facilities is the capital cost, and given that the reactors being considered are mostly Generation IV reactors that haven't been mass-produced yet, there is a possibility of some capital cost fluctuation. This section will analyze the sensitivity of the facility cost in Scenario 3 to these fluctuations.

PBMR

$$\Delta P = 25\%$$

$$\text{Capital Cost} = \$1274.9 \text{ M}$$

$$\text{Capital Cost}_{new} = (1.25) \cdot (\$1274.9 \text{ M})$$

$$\begin{aligned}
&= \$1593.4 \text{ M} \\
\text{Total Cost} &= \$2817 \text{ M} \\
\text{Total Cost}_{new} &= \$(2817 - 1274.9 + 1593.4) \text{ M}) \\
&= \$3135.5 \text{ M} \\
\Delta \text{Total Cost} &= \frac{3135.5 - 2817}{2817} \\
&= 11.3\%
\end{aligned}$$

ACR-700

$$\begin{aligned}
\Delta P &= 25\% \\
\text{Capital Cost} &= \$2145 \text{ M} \\
\text{Capital Cost}_{new} &= (1.25) \cdot (\$2145 \text{ M}) \\
&= \$2681.3 \text{ M} \\
\text{Total Cost} &= \$3853 \text{ M} \\
\text{Total Cost}_{new} &= \$(3853 - 2145 + 2681.3) \text{ M}) \\
&= \$4389.3 \text{ M} \\
\Delta \text{Total Cost} &= \frac{4389.3 - 3853}{3853} \\
&= 13.9\%
\end{aligned}$$

AP600

$$\begin{aligned}
\Delta P &= 25\% \\
\text{Capital Cost} &= \$1824 \text{ M} \\
\text{Capital Cost}_{new} &= (1.25) \cdot (\$1824 \text{ M}) \\
&= \$2280 \text{ M} \\
\text{Total Cost} &= \$3646.7 \text{ M} \\
\text{Total Cost}_{new} &= \$(3646.7 - 1824 + 2280) \text{ M}) \\
&= \$4102.7 \text{ M} \\
\Delta \text{Total Cost} &= \frac{4102.7 - 3646.7}{3646.7}
\end{aligned}$$

$$= 12.5\%$$

According to the calculations, a 25% spike in the capital cost of building nuclear reactors would result in 11.3%, 13.9% and 12.5% increases in total cost. While this is certainly significant, an error of 25% in our capital cost estimates is highly unlikely, and the total cost for nuclear is much less sensitive to uncertain shifts than natural gas facilities. As such, nuclear is a safer option because it is much less volatile.

9.3 Economic Comparison of Natural Gas-Fired Plants versus Nuclear Generated Plants

The economic decisions that must be made at this point are underlined by the following three points:

- Should natural gas or nuclear technology be used for the SAGD extraction process?
- Should the electricity requirements of the plant be fulfilled by buying electricity off the power grids, or making it at the plant?
- Should the hydrogen required for the bitumen upgrading process be bought from private suppliers, or produced at the plant?

To look at these questions from the standpoint of cost, Table 9.3 provides a quick summary of the results calculated in this section.

		Natural Gas	PBMR	ACR-700	AP600
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 Hydrogen	2.506	2.506	2.506	2.506

Table 9.8: Summary of Results

Nuclear is much cheaper than natural gas for the SAGD process, while they are comparable in the cost of producing hydrogen. Add the fact that the price of natural gas is very volatile, as discussed in section 9.1, nuclear technology has a clear cut advantage

over natural-gas economically, and thus is the best choice for use in the SAGD process. Among the three reactors considered, the PBMR technology is the cheapest, but the other non-economic factors, such as political feasibility and Canadian nuclear fuel enrichment concerns might make the other reactor technologies, especially the ACR-700, more viable.

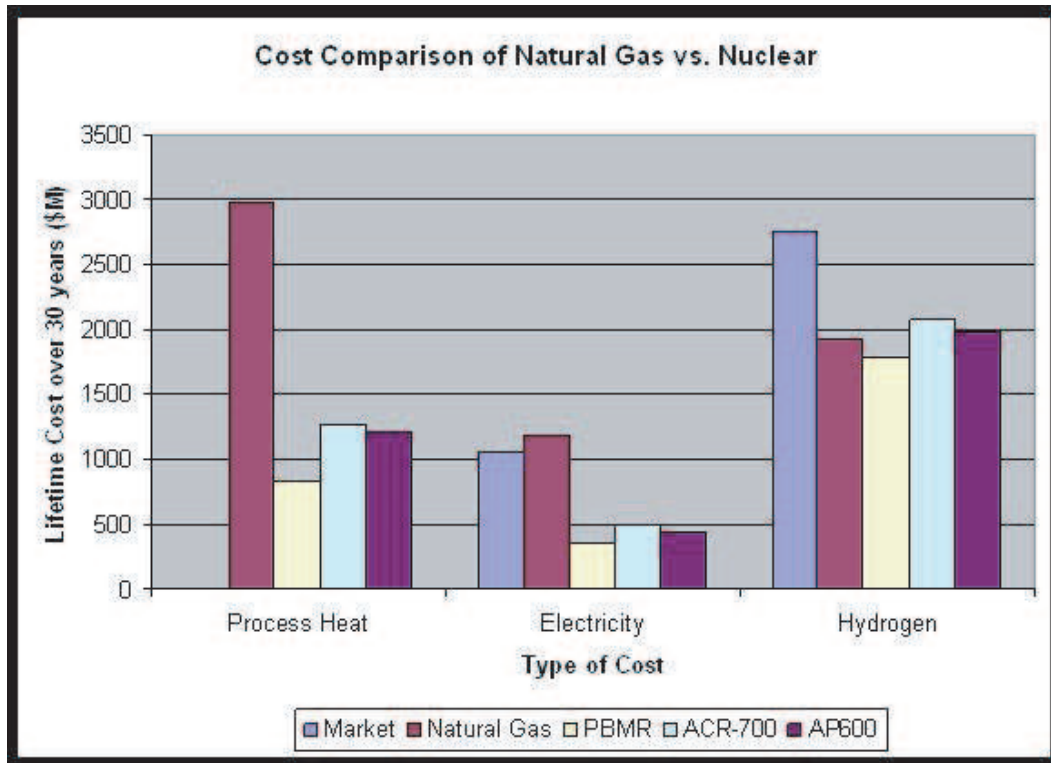


Figure 9.4: Cost Comparison

Given that nuclear technology will be used for the facilities, electricity should be produced by the plants themselves rather than bought since it is much more cost-effective and there is no guarantee that there will be an existing grid capable of supporting the plant needs at the site in the first place. The same will be true for hydrogen, i.e. it should be produced internally instead of being bought in the private market. This is true not only because it is the cheaper option, but also for two other important reasons. First, there might not be adequate supply of hydrogen from private suppliers because of production constraints and lack of viable transportation (i.e. pipelines) to the site. Second, private suppliers currently produce hydrogen using natural gas technologies making the prices highly susceptible to the volatile energy market discussed earlier and this might be a very unattractive option in the long run.

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.

Chapter 10

Canada's Disposal Plan for Nuclear Waste

All nuclear power plants release small amounts of radioactive substances during normal operation. Coal-powered plants also release radioactive substances into the environment due to radioactive impurities in the coal, even though coal itself is not thought of as radioactive material. The United Nations Scientific Committee on the Effects of Atomic Radiation has stated in 1997 that the average annual radiation exposure in millirems a person would receive from living near both types of plants is approximately equal [77]. A party producing radioactive waste is responsible for the disposal of the waste, including funding, management, and development of storage facilities. The responsibility of the federal government is to develop policy and to regulate and oversee radioactive waste producers and owners so that the owners meet their responsibilities [78]. The national law for the management of nuclear waste is the Policy Framework for Radioactive Waste which was created by the Government of Canada in 1996. The CNSC is charged with regulating low-level waste and their policy is found in the Draft Regulatory Policy P-290 Managing Radioactive Waste [78].

10.1 Low Level Waste

The International Atomic Energy Agency defines low-level radioactive waste as all forms of radioactive waste except for spent fuel waste and wastes from fuel mining and milling [78]. All low-level radioactive waste is currently in storage, since Canada has no disposal facilities. There is currently no pressing need for disposal because current volumes are very small. The average annual quantity of solid low-level waste from a single ACR-700 unit is only about 23 cubic meters [37]. The main source of Canadas low-level waste is

from the production of electricity; Ontario Power Generation currently produces 70% of the country's low-level waste.

Most of Canada's historic low-level waste is located in the southern Ontario communities of Port Hope and Clarington [78]. The Canadian government and the local municipalities where the waste is located made an agreement in March 2001 to have the waste cleaned up and put into above-ground mounds in the local communities. The project is funded by the Government of Canada, managed by the Low-Level Radioactive Waste Management Office, and expected to be completed in 10 years.

In Alberta there is waste currently being stored in Fort McMurray (42,500 m³), and at the research reactor at the University of Alberta (less significant amounts) [79]. There are other initiatives in place to help dispose of the low-level waste. One initiative is the Intrusion Resistant Underground Structure, a below-ground vault with reinforced concrete walls and roof and a permeable floor. There are multiple barriers to minimize water entry into the stored waste and also prevent the accidental release of radionuclides to the environment. The structure is expected to maintain the waste for at least 500 years. Underground storage facilities are already in use in Canada but they are not designed for long-term use [78].

Low-level waste for an ACR-700 facility would be stored on-site in 200-liter drums or stored for a short period of time (about 10 years) at the maintenance building. From there, the drums would be shipped off for final disposal once a permanent geological waste repository is found [37].

Low-level waste from a PBMR can be safely stored on-site for 40 years, thanks to the silicon-carbide coating of the fuel pebbles.

10.2 Spent Fuel

10.2.1 Regulation

Spent fuel is the term used to describe fuel that has already been used in a nuclear reactor, and it is highly active due to the fission products that remain. Spent fuel is currently considered another form of radioactive waste (often it is referred to as high-level waste). Therefore, policies that govern radioactive waste are also used for spent fuel. This includes nuclear fuel bundles from CANDU power reactors, prototype and demonstration power reactors, and research and isotope production reactors [78]. The CNSC regulates spent fuel as well as low-level radioactive waste.

10.2.2 Wet Storage

All Canadian spent fuel is either stored in wet or dry interim storage areas. When the fuel is discharged from the CANDU reactors it is placed underwater in a spent fuel storage bay so that it is properly shielded. The fuel is usually kept there for a number of years and then sent to an interim dry storage facility. Fuel from the AP600 is treated the same way, first cooling in a spent fuel pool, and later stored on-site in dry storage containers for up to 100 years.

The pools for the wet storage have several purposes. They provide a cooling and purification system, containment for the spent fuel, shielding of radiation, and allow remotely-operated access to the spent fuel for examination [78]. Wet storage has been researched and utilized in Canada since the first facility at the AECL research reactor in 1947 was established [78].

10.2.3 Dry Storage

Ontario Power Generation, Inc.'s dry storage containers are rectangular shaped, made out of reinforced concrete, and weigh 53 tons. They can hold 384 fuel bundles which will give them a full weight of 63 tons. A helium cover-gas is used to prevent the fuel from going through oxidation reactions [78]. The interior and exterior layers of the containers are lined with carbon steel to provide a containment boundary and to enhance structural integrity [78]. These storage containers are meant to be kept indoors to supply further shielding. The AP600 would utilize similar (perhaps the same) dry storage containers. It produces the same variety of waste as typical PWRs, but produces less per megawatt than the average PWR.

Another type of dry storage containment used is the AECL MACSTOR Module. It is currently only in use at the Hydro-Quebec Gentilly-2 Spent Fuel Dry Storage Facility. Each module is very large and can hold up to 12,000 spent fuel bundles, each 8.2m wide, 20.4m long and 6.4 m high. See Figure 10.1. A module stores 20 canisters in two rows of 10 vertical cylindrical cavities, each holding 10 baskets of 60 spent fuel bundles. The spent fuel is cooled down by natural circulation of the air through the ventilation ports extending through the concrete walls [78]. The inlets and outlets of the ventilation ports are arranged in baffles to avoid the gamma radiation given off by the fission products in the spent fuel.

Research programs have found that the dry storage conditions of the MACSTOR are sufficient to contain spent fuel for at least 100 years before integrity is lost. The collective occupational radiation exposures at the Pickering Used Fuel Dry Storage Facility have

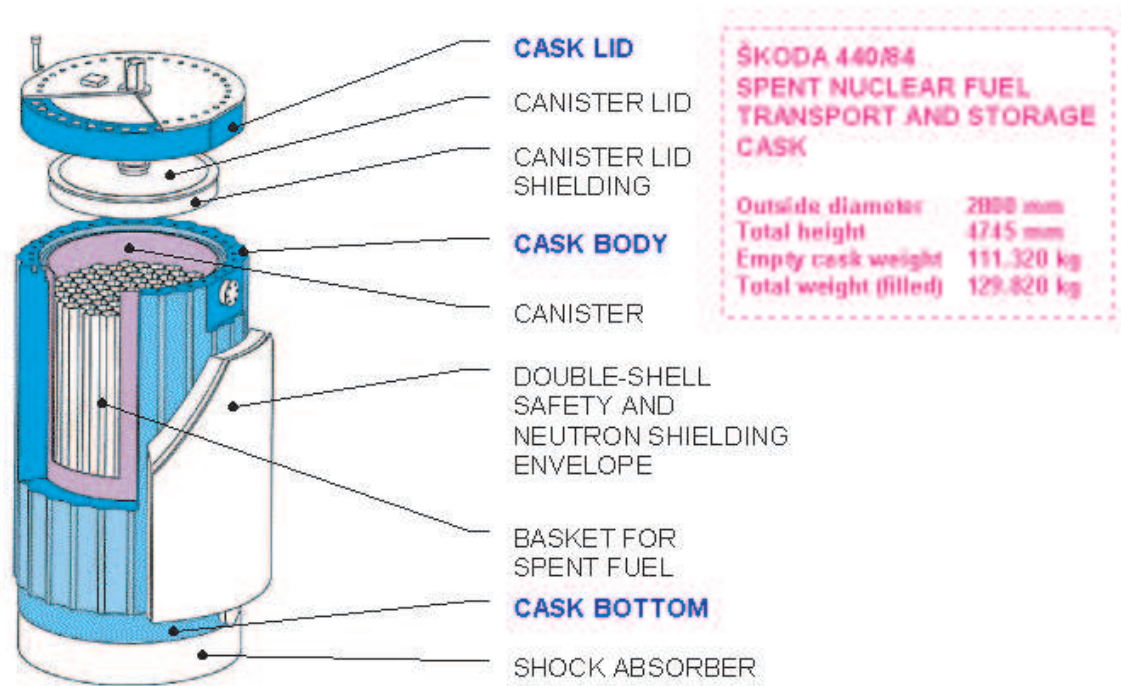


Figure 10.1: A typical cylindrical container for spent fuel storage, like the MACSTOR. (Source: [80])

been less than predicted exposures by 30% or greater. There have also been no reports of effluent release from the storage areas.

All spent fuel is currently held in interim storage until the Government of Canada can decide upon a long-term management method [78]. According to [81], Canada currently has established an underground repository laboratory and plans to use this repository for storing spent nuclear fuel by 2025. This means that for a plant completed in 2015, on-site storage can more than handle the waste output until an underground repository in Canada, 500 to 1000 meters below the surface, is opened.

10.2.4 PBMR Spent Fuel Storage

The spherical graphite fuel pellets of the PBMR are advantageous when compared to other forms of nuclear fuel in storing fuel waste. The fuel of a PBMR fuel pellet is encapsulated in a silicon-carbide layer which prevents the fission fragments from escaping when it is put into storage. It would take seven billion years for a centimeter of the graphite layer to be oxidized at 150°C [82]. For the first fifteen years of storage, the average temperature of the fuel is expected to be only 134°C and the outer protective shell of the fuel pebble is 0.5 cm thick. The type of graphite used for the pebbles is non-combustible and is one of the most inert elements on the periodic table, meaning the

graphite will not decay or release radiation.

Currently, there are no waste containers in Canada that are designed specifically for PBMR fuel. However, the graphite pebbles can be stored in the same storage containers that are designed for CANDU fuel bundles. A storage container that is designed to hold 72 CANDU fuel bundles is capable of holding up to 4000 fuel pebbles with a packing fraction of 0.64 [82]. The graphite pebbles are durable enough to simply be poured into the storage and transfer casks, rather than require a complicated individual placement of the fuel.

10.2.5 Liquid Waste

Although nuclear reactors do produce liquid radioactive waste, there is no concern that radioactive substances could contaminate the oil sands or water used in the bitumen extraction process. Liquid waste from a PBMR is pumped by existing pipelines out to sea in current plans for this reactor design in other locations. The AP600 has been said by peer review to have an adequate liquid waste management system, and that system is similar to that of the ACR-700. The liquid waste management system of the ACR-700 is designed to monitor, collect, and eliminate the liquid waste in a safe manner that minimizes the probability of contamination into the environment with the use of concrete storage tanks. Liquid wastes can come from the spent fuel storage pool, underdrainage ground water sump, reactor auxiliary building underdrainage sump, heavy water areas and detergents used in showers for decontamination [37].

Liquid waste produced inside the reactor building is collected in the drainage system and transferred by a sump to certain storage tanks depending upon its level of activity. This prevents the liquid waste from contaminating the water in the surrounding environment or oil sands. Each storage tank has its own pump which re-circulates the waste in order to dilute the active material in the tank. The pump also discharges the waste into the local sewer system when the activity of the liquid waste is low enough. The tanks are designed so that if one of the tanks should overflow, the extra liquid would go into another tank. If liquid would overspill from all of the tanks, then there is a drain system in the storage area that would collect the extra liquid.

Samples from the tanks are taken and sent to a lab before a tank is allowed to discharge its contents. If there are no problems with the sample, the discharge pump sends the liquid waste into the sewer system and a liquid effluent monitor surveys the activity level. If the monitor receives a reading that is above a certain set point, then an isolating valve will close and prevent the waste from leaving the tank [37].

10.2.6 Gaseous Wastes

The gaseous waste system of a typical nuclear reactor controls the moderator enclosure driers, filters for particulates, and limits the release of radioactive noble gases. Contaminated air passes through a set of filters before it passes out through the common exhaust stack.

A vapor recovery system is available to prevent the heavy water vapor from escaping. Dehumidifiers take effluent from the system and separate out the heavy water. The heavy water is returned to the heavy water moderator system through the cleanup loop. This system helps to recover 95% of the heavy water vapor.

An off-gas management system is in place to manage the noble gases that are released into the environment. An activated charcoal filter delays some of these gases for 28 days to allow them time to decay. This allows an isotope such as xenon-135, which has a half-life of 5.3 days, to have its activity reduced by a factor of 40 when it is released into the environment [37].

Chapter 11

Nuclear Obstacles

While nuclear energy may be more cost effective and environmentally preferable to using fossil fuels in Canada, there are obstacles which need to be addressed. First, the negative public perception of nuclear power is a potential problem, and requires a public information effort as part of the decision to build. This effort must include the following: information for the local community, public exhibitions, a publicly accessible plant, and work with schools and educational establishments. With open dialogue between management and the surrounding population and the building of additional reactors, the public will begin to understand how the plants operate, and they will become more comfortable with nuclear energy.

Oil companies have not been involved in nuclear energy in the past and are hesitant to use it based on their perceptions of the difficulties in licensing and running a nuclear reactor. As shown in Chapter 7, the licensing process requires the Canadian Nuclear Safety Commission to be familiar and comfortable with a reactor for it to be licensed. Ultimately, the CNSC will license any reactor that is proven to work. Therefore, depending on the reactor chosen, the cost of licensing will vary greatly. If a previously licensed reactor is used, the cost will be less because the CNSC will not need to licence a new design. Currently, Atomic Energy of Canada Limited is the only company producing reactors in Canada. A decision to build an American reactor would not only cause increased licensing expenses, but it would be met with more public opposition because of the reduced Canadian economic benefits.

Though there are obstacles to the use of nuclear power, there are 104 commercial reactors licensed and safely running in the United States. These reactors are both safe (1 major accident in the lifetime of the industry), and cost effective. A measure of cost-effectiveness is the capacity factor, or the ratio of the electricity generated by a power plant compared to the electricity that could have been produced if the plant had operated at full power, nonstop. Since the 1980's there has been an upward trend in the capacity factor for all

104 U.S. commercial nuclear power plants, and nearly half of these reactors have capacity factors of 90 percent or more from the start of 2001 through the end of 2004 [83]. This is considerably higher than the average natural gas plant, which has a capacity factor of around 80 percent.

Chapter 12

Conclusion

12.1 Summary

The purpose of this report was to analyze the feasibility of using nuclear energy to replace the natural gas that is currently used at Canadian oil sands extraction facilities. As the need for in-situ extraction is expected to be far greater than the need for surface mining in the future, this report focuses on facilities using SAGD, the preferred in-situ extraction method. Oil sands facilities have large steam and electricity demands, while installations performing on-site upgrading also require large quantities of hydrogen. Existing projects use natural gas technologies to satisfy these demands, but nuclear energy is well-suited for these requirements and needs to be addressed as an alternative.

Oil sands production growth is limited by the dependence on water, shortage of diluent, increasing cost of natural gas, and greenhouse gas emissions. Water, as steam, is used to separate bitumen from sand in both mining and in-situ oil sands operations. Drought in Alberta has increased public awareness about water conservation. Diluent must be added to the viscous, unprocessed bitumen to decrease the viscosity of the mixture so it can be transported via pipelines. Oil sands operations are estimated to increase production to 2.4 million bbl/d by 2012, and there is already a shortage of diluent. As mentioned above, natural gas is the energy source used to fuel oil sands operations. The profitability of these operations decreases as the price of natural gas increases. If the price of natural gas continues to rise, oil sands operations will no longer be cost effective. Canada is concerned with the climate change associated with greenhouse gases. Canada is required to decrease CO₂ emissions from 612 megatonnes in 1990 to 575 megatonnes in 2012 because of the Kyoto Protocol. Canada's Climate Change Plan, revised in 2005, estimates that greenhouse gas emissions can be reduced by 270 megatonnes with enough federal funding. Assuming the estimated growth of the oil sands industry, CO₂ emissions could

reach 100 megatonnes by 2012, 17% of the total desired emissions in 2012. Oil sands projects fueled by nuclear technology will also have diluent and water limitations, but will provide solutions to the increasing cost of natural gas and greenhouse gas emissions. Nuclear technology does not rely on natural gas, so it will not be affected by the rising cost. Also, nuclear is emissions-free, solving the problem concerning CO₂ emissions [62].

This report considered three possible scenarios for utilizing nuclear energy for oil sands production. For each of these scenarios, the thermal and electrical energy that would be required was calculated. These calculations were performed for a reference plant producing 100,000 barrels of bitumen per day. The first two scenarios are for plants that produce dilbit as a final product; the third scenario is for a plant that produces dilbit and then upgrades it on-site to produce syncrude as a final product.

In the first scenario, the reactor is used to produce SAGD steam only. Electricity for the extraction facility is drawn from the grid. This scenario was determined to have a thermal energy requirement between 820 MWth and 1,264 MWth. In the second scenario, the reactor produces the extraction facility electricity as well as SAGD steam. For this scenario, 1,200 MWth and 250 MWe are needed. In the third scenario, the reactor produces SAGD steam and electricity for the extraction facility, as well as additional electricity for an on-site upgrader and electricity and heat required for hydrogen production. Hydrogen is essential for upgrading bitumen, therefore it must be produced at the facility if upgrading is to be performed on-site. High temperature steam electrolysis will be used for hydrogen production with a nuclear reactor. The energy requirements for Scenario 3 were calculated to be 1,300 MWth steam and 740 MWe.

Although 11 different reactors were initially considered for use at oil sands facilities, three were determined to be the most appropriate for this application. These are the ACR-700, a pressurized, on-line refueling, heavy water moderated, light water cooled reactor made by Atomic Energy of Canada Limited; the Pebble Bed Modular Reactor, a 400 MWth, high temperature, helium-cooled, online refueling gas reactor that is currently under development; and the AP600, an advanced PWR boasting passive safety features designed by Westinghouse Electric Company. An evaluation of the benefits and drawbacks of using each of these reactors for oil sands was made. Based on the energy requirements of each of the three scenarios and the maximum thermal powers of these reactors, it was determined that one AP600 or four PBMRs would be appropriate for Scenario 1; one ACR-700 or five PBMRs could be used for the second scenario; and two AP600s, two ACR-700s, or eight PBMRs would be appropriate for Scenario 3.

The economics of using nuclear energy for oil sands facilities versus those for using natural gas were compared by making calculations of the lifetime costs for facilities using each of the two options. Individual calculations for the costs of steam, electricity, and hydrogen

production were made for each of AP600, ACR-700, and PBMR reactors, as well as for natural gas. For steam production, nuclear energy was found to be less than half as expensive as using natural gas. Using nuclear for electricity production was calculated to be one-third to one-half the cost of buying electricity off the grid or producing it on-site using natural gas. Nuclear energy used in conjunction with high temperature steam electrolysis for producing hydrogen was also determined to be cheaper than producing hydrogen using natural gas. Among the various reactor options, the PBMR was determined to be the least expensive; however, the ACR-700 and AP600 should be economically feasible as well.

This report also discusses some of the other issues surrounding the use of nuclear energy for oil sands, including licensing, siting, disposal of nuclear waste, and potential obstacles to using nuclear energy for Canadian oil sands.

Licensing of the ACR-700 for this project should be the easiest, as the Canadian Nuclear Safety Commission (CNSC) is already very familiar with CANDU reactors and somehow familiar with the ACR-700 itself. Licensing of the AP600 might be more difficult due to the Canadians' relative unfamiliarity with PWRs; however this reactor has been approved in the United States, so it should ultimately be able to gain certification in Canada as well. The PBMR will likely be the most difficult to license since it has yet to go through the licensing process anywhere other than Germany.

There are a number of siting considerations that must be taken into account for a reactor at an oil sands facility. These include water usage limitations and limitations of piping steam from a central reactor to well pads spread over a large area. Also, a piece of land suitable for a reactor site must be chosen from the available land at a particular extraction facility. This report provides some discussion of the issues surrounding reactor siting; however, a detailed analysis specific to a particular site would need to be performed before a nuclear powered oil sands facility could be implemented at that site.

Canada is currently planning a high level nuclear waste repository that is scheduled to open in 2025. Due to the extended time that it would likely take to implement the plan outlined in this report, this repository should be available by the time it would be needed for waste produced by oil sands nuclear facilities.

Other potential obstacles to using nuclear energy for oil sands include public perception and the lack of experience of oil sands companies with nuclear technology. The former problem could be solved by an education program for the people living in Northern Alberta. It is expected that an electric utility with experience in nuclear operations could be brought in to operate the reactor for the oil companies, as this would prevent the oil sands companies from having to gain the needed experience and expertise.

12.2 Future Work

The combination of nuclear technology and oil sands technology is one with great growth potential and there are many aspects of the process that require further investigation and development. A number of system enhancements currently in the concept phase could potentially increase production and profitability.

Issues that merit further study include limitations on piping steam, restricted access to water, shortage of diluent, transportation into the oil sands region, and constructability of the facilities. A large increase in the production of the oil sands regions could overwhelm the capacity of the pipelines in the area, and improvements to the pipeline infrastructure might be needed. The development of the ability to use brackish water, which is in greater supply than fresh water, would aid in the water conservation efforts. A central nuclear power plant, with smaller peripheral natural gas plants, could provide an interesting option for extending the feasible distance of the wellpads from the nuclear power plant. Since that distance is limited to the short distance over which steam can be effectively piped, a central nuclear plant could be used to heat water. The warm water could then be piped via heated pipelines to distant wellpads where it would be converted to steam by a small natural gas plant.

For higher profitability, the efficiency of the system needs to be maximized. An integrated computational fluid dynamics model of all of the flows in the system would enable a detailed and reliable optimization of the reactor outlet temperatures and pressures, as well as the steam generators' characteristics. The efficiency loss incurred by adding an intermediate loop between the primary coolant and the steam generator should be determined. The benefit of isolating the primary coolant could then be weighed against the drawback of efficiency loss. Improvements in reservoir simulations would aid in planning the lifetime operating states of a SAGD site. Steam chamber tracking technology could help to lower the steam to oil ratio, which is always favorable, since steam production accounts for a sizeable portion of the operating costs.

Another system scenario that could be considered is one in which a full refinery is located on or near the site, enabling the extracting company to fully refine their bitumen to a final product, which would be more valuable and would attract a wider market than bitumen or syncrude.

Appendix A

Chosen Reactor Designs; a detailed treatment

A.1 Advanced Candu Reactor (ACR-700)

A.1.1 Fuel Type

The ACR-700 is fueled with the newly designed CANFLEX fuel bundles containing slightly enriched uranium (SEU). A cutaway photo of a fuel bundle in its housing is shown in Figure A.1. The bundle is 0.5m long, and contains 43 fuel rods, 42 of which contain UO_2 pellets of 2.1% by weight uranium-235. The center and inner ring consist of eight elements with a diameter of 13.5 mm, whereas the outer two rings consist of 35 elements with a smaller diameter of 11.5 mm. The central rod contains natural uranium and 7.5% dysprosium, a burnable neutron absorber. A schematic diagram illustrates the fuel element geometry in Figure A.2. The fuel claddings are made of Zircaloy-4 and are lined with graphite CANLUB for fuel failure protection. The CANFLEX fuel is manufactured by Zircotec Precision Industries Inc in Ontario, Canada [39][84].

A.1.2 Core Geometry

The ACR-700 core is characterized by horizontal fuel channels with low temperature, low pressure heavy water as a moderator in the steel core vessel which is called the calandria. (Smaller vessels, also called calandria, surround each fuel assembly and pressure vessel.) Light water coolant fills the rest of the reactor vessel. The ACR-700 has 292 fuel channels, the design of which is illustrated in Figure A.3. Each channel contains 12 fuel bundles, and they are arranged in a square lattice with a pitch of 220 mm. The length of the core is



Figure A.1: CANFLEX fuel assembly cut-away view inside pressure tube and calandria (Source: [85])

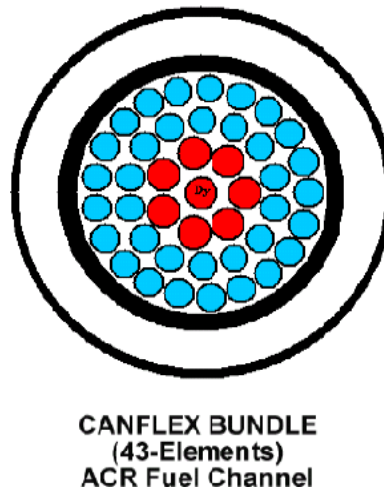


Figure A.2: Fuel element geometry in CANFLEX assembly (Source: [86])

5.94 meters, and the inside diameter of the calandria main shell is 5.2 meters [84][40]. The heavy water reflector that surrounds the perimeter of the core is 48 cm thick [84]. The design of the overall core housing including calandria main shell penetrations is shown in Figure A.4.

A.1.3 Safety Systems/Reactivity Control

The ACR-700 follows the current trend towards passive safety with its two independent shut-down systems. In shut-down system one, the control rods, driven by gravity, drop into the moderator. In shut-down system two, pressurized gas is used to inject liquid absorber into the moderator and reflector.

For emergency core cooling, the reactor has a two-stage system, illustrated in Figure A.5. First, pressurized tanks in the containment inject water into the reactor through the emergency coolant injection system, and then long term cooling is provided by sump pumps [86].

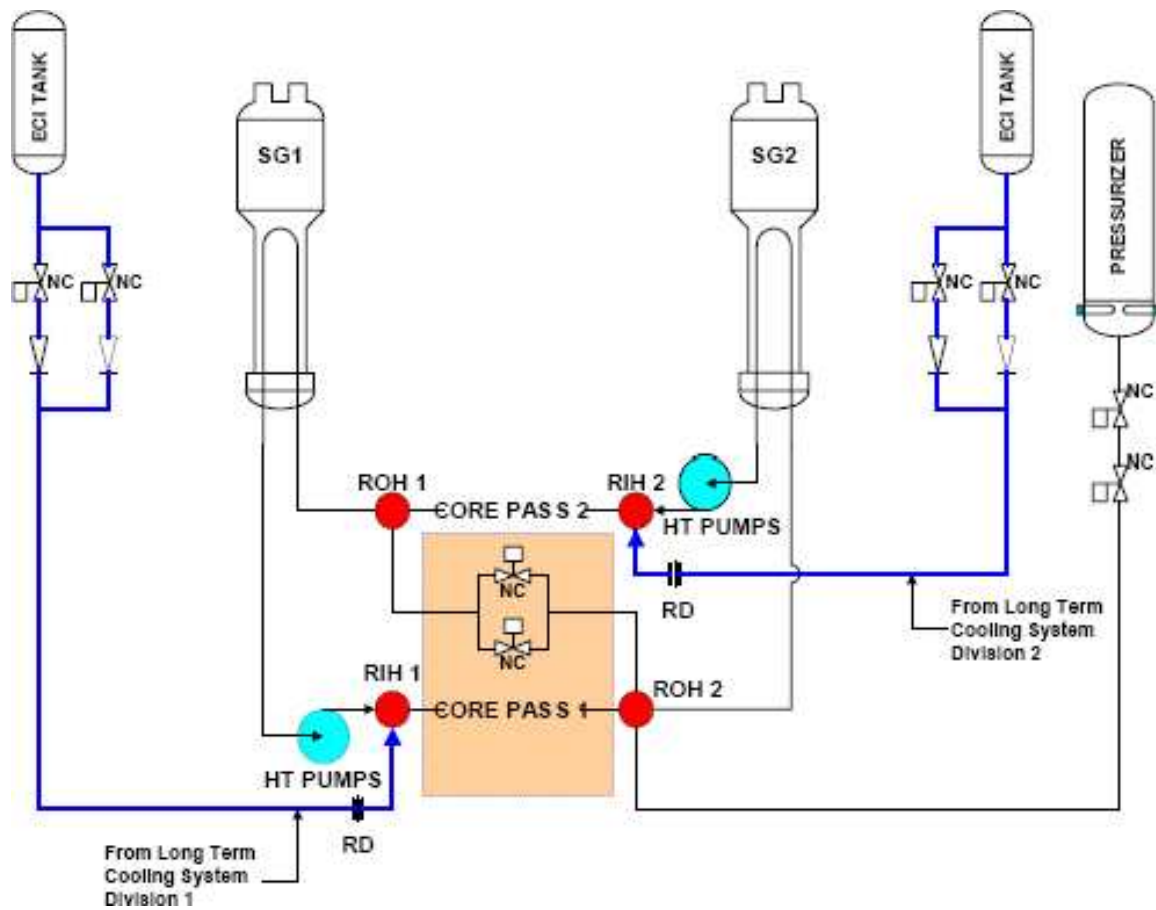


Figure A.5: ACR-700 Emergency Core Cooling System (Source: [86])

In a loss-of-cooling accident (LOCA) simultaneous with a loss-of emergency core cooling, the moderator can be used as a coolant to prevent fuel melting.

In the case of a severe core damage scenario, which can only be caused by highly improbable multiple failure modes, the moderator and shielding water lab can be boiled off to delay damage, and the fuel can be contained in the calandria using the reserve water system for make-up to the shield tank [86].

A.1.4 Primary Coolant

The heat transfer system consists of a figure-8 loop through which light water coolant is circulated bi-directionally through the fuel channels and then to the steam generators and the turbines. A flow diagram of the heat transfer system is shown in Figure A.7.

The inlet and outlet values for the coolant are shown in Table A.1.

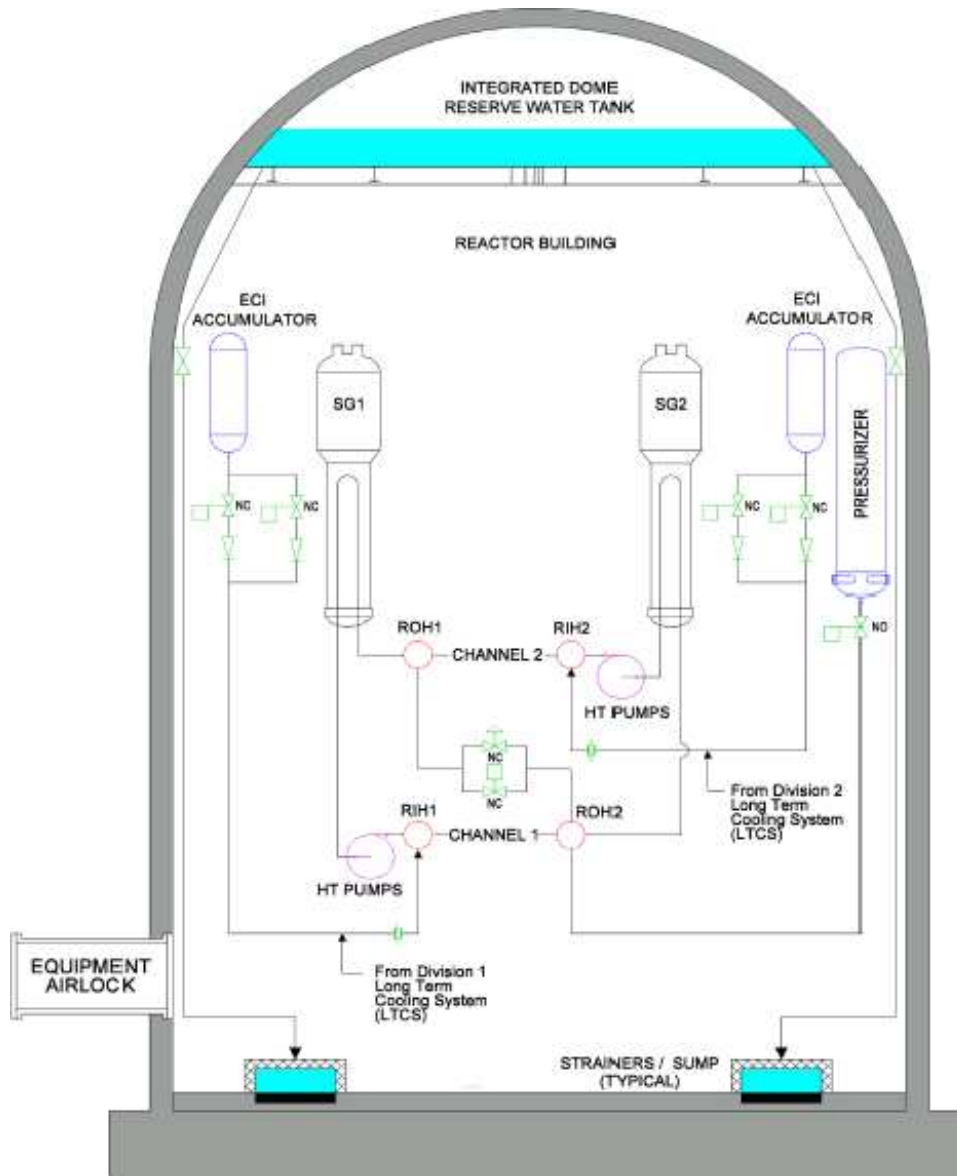


Figure A.6: ACR-700 Emergency Coolant Injection system (Source: [86])

Temperature at the Fuel Channel Inlet	280C
Temperature at the Fuel Channel Outlet	328C
Pressure at the Fuel Channel Inlet	13.2 MPa (g)
Pressure at the Fuel Channel Outlet	12.3 MPa (g)
Mass Flow Rate	26 kg/s

Table A.1: ACR-700 Core Thermodynamic Data (Source: [40])

A.1.5 Plant Size

The ACR containment is constructed of pre-stressed concrete with a steel liner and has an inner diameter of 39.5 m and an inner height of 59 m. It is built to withstand a LOCA pressure of 250 kPa(g) and a Main Steam Line Break (MSLB) pressure of 450 kPa(g). It has a wall thickness of 1.2 m and a net air volume of 47,800 m³. The exclusion zone

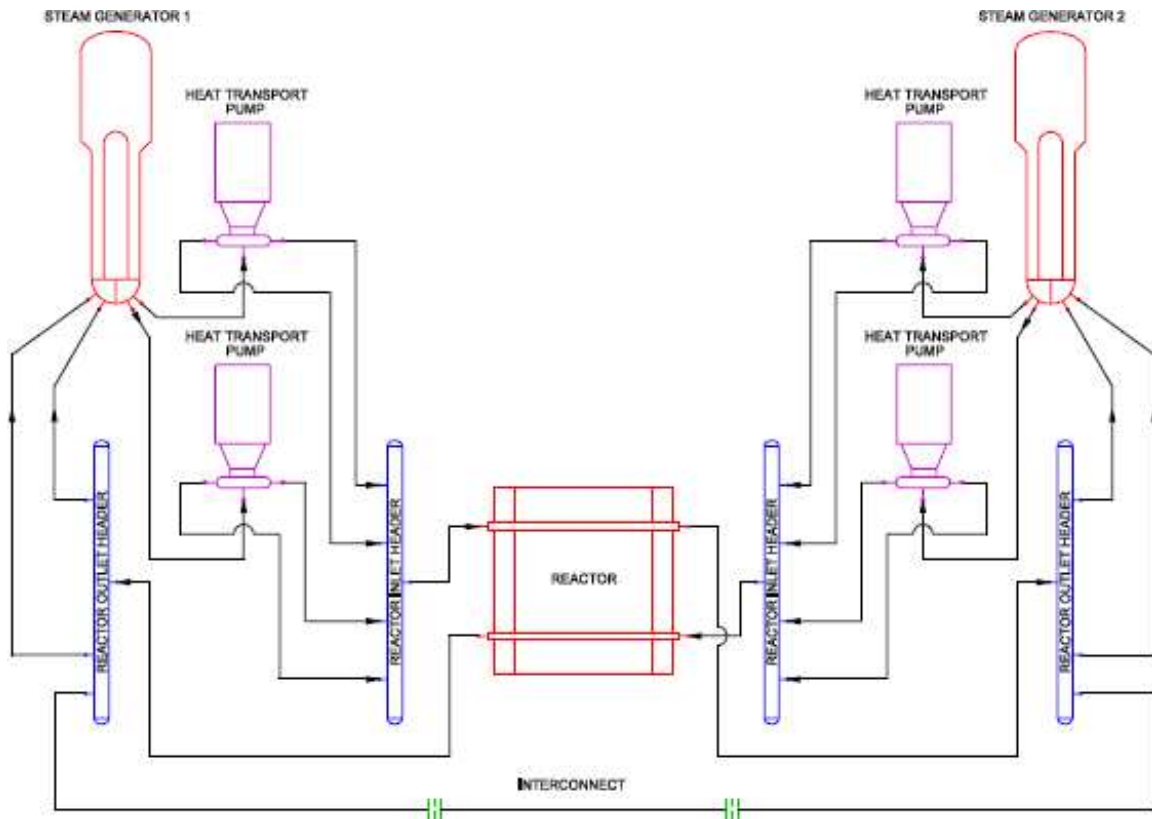


Figure A.7: Heat transfer system flow diagram (Source: [84])

(restricted access area) for the reference plant design has a radius of 500 m [40].

A.1.6 Constructability

Much planning and design has gone into the construction plan for the ACR-700, such that it would be feasible to build the plant in the Athabasca region of Alberta, despite the distance from water shipping routes. The construction process for the ACR-700 uses parallel construction techniques and modular assembly to decrease schedule and cost overruns.

Of particular importance to this project is the assembly of the reactor building, since that could prove to be the most difficult undertaking far from a seaport. A detailed plan has been made for the construction of the reactor building, and it is illustrated in Figure A.8.

Aside from the well-designed construction plan for the reactor, another factor that enables the reactor to be more easily built in Alberta is that there are rail lines directly into the region of the oil sands.

Cold Lake, Fort McMurray, and Athabasca are all located on major rail lines originating in Edmonton, Alberta. Canadian National (CN) and Canadian Pacific (CP) both have



Figure A.8: ACR-700 construction sequence for first unit (Source: [40])

lines from Vancouver to Edmonton, but the horizontal clearance on those routes is at best 4 meters (13 feet and 4 inches). It is also possible to transport equipment by train from Duluth, Minnesota, a shipping port on Lake Superior, accessible via the St. Lawrence Seaway. The maximum horizontal clearance on that route is 4.3 meters (14 feet and 4 inches), which makes it more useful than the Vancouver route for shipping large equipment. Also, if necessary, the three oil sand regions can be approached closely from Edmonton using lines owned by RaiLink Mackenzie Northern (RLMN), RaiLink Lakeland & Waterways (RLW), Grand Prairie Grand Cache (GPGC), Burlington Northern Santa Fe (BNSF), CN, and CP. There are few tunnels or bridges in that area, so transporting large equipment is not difficult, and in fact CN and BNSF have a great deal of recent experience shipping oversized loads to the Fort McMurray region [87] [88].

The roadways in northern Alberta are limited, and some of them are unpaved. Any oil sands extraction site would need to build access roads to their site if they do not exist already, but the land is amenable to that, since it is largely flat open space.

According to [69], the ACR-700 “is designed to enable road shipment of all modules from Edmonton to the Fort McMurray and other site areas,” so transporting the components

for this design should not be a major concern.

A.1.7 Two-Unit ACR for Power Increase

If more than 700 MWe is needed, for example in the case of hydrogen production, the ACR-700 is designed to be used for a two-unit power plant that would supply approximately 1,406 MWe. AECL has proposed a two-unit plant that is in the pre-licensing stage of the regulatory process. A schematic of the proposed two-unit layout is shown in Figure A.9.

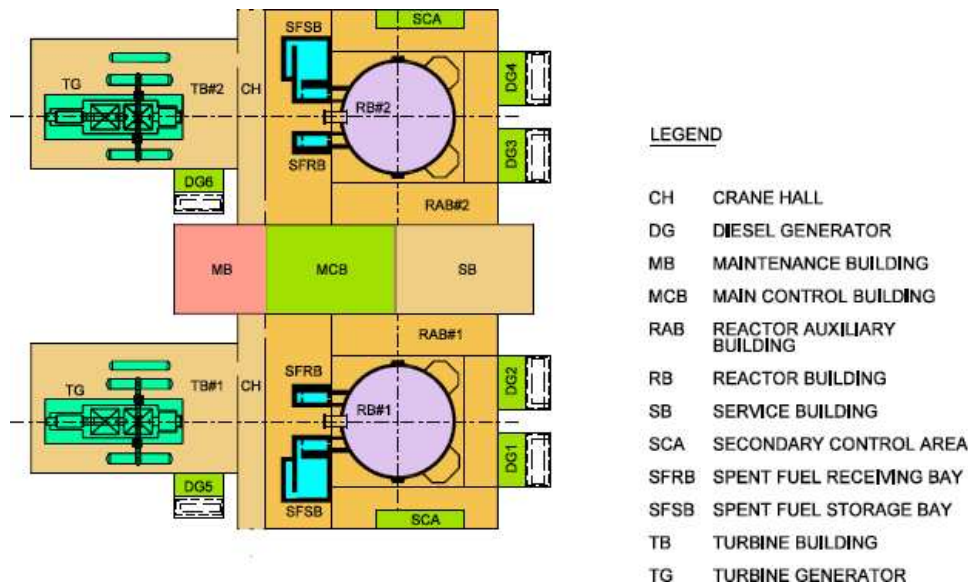


Figure A.9: Two-unit ACR plant layout (Source: [40])

The components of the two reactors would be identical to those of the ACR-700 described in the previous sections. One benefit of having two reactors is that while the power is doubled, some of the support systems and facilities can be shared. These include:

- Main Control Building
- Maintenance Building
- Service Building
- Administration Building
- Switchyard Area
- Water Treatment Plant
- Sewage Treatment Plant

- Radioactive Waste Storage Facility
- Guard House
- D₂O Supply System
- H₂O Supply System
- D₂O Cleanup System
- Chilled Water System (non-seismic qualified portion)
- Service Air System
- Breathing Air System
- Compressed Air System
- Firewater System
- Demineralized Water System
- Domestic Water System [40]

A.2 Pebble Bed Modular Reactor (PBMR)

A.2.1 Fuel Type

The PBMR uses “TRISO-coated” (TRISO is shorthand for TRI ISOtropic) fuel microspheres that are embedded in a graphite matrix. This graphite fuel matrix, which contains approximately 11,000 fuel microspheres, comprises the core of each fuel pebble. A 5 mm thick layer of graphite encapsulates the core fuel matrix, providing moderation, and a strong containment vessel to prevent the expulsion of radioactive material. The whole fuel pebble is 60 mm in diameter, approximately the size of a tennis ball, weighs 210 g, and contains 7 g of uranium, as illustrated in Figure A.10 [43]. Approximately 380,000 fuel pebbles are loaded into the PBMR core vessel.

A 0.5 mm diameter fuel kernel made of (on average) 8% uranium-235 enriched UO₂ [73] is at the heart of every fuel microsphere. Four layers of protective coating surround the fuel kernel. The innermost layer is 0.090 mm thick and made of a porous carbon buffer. [44] The carbon buffer prevents fission products from escaping, provides a fission product gas volume, and limits swelling. Outside of that is a layer of pyrolytic carbon, 0.040 mm thick. This layer also prevents the outward migration of fission products. The next

layer is a barrier coating of silicon carbide, 0.035 mm thick. This barrier coating provides overall particle strength, and stops migration of certain fission products; in particular solids like barium and strontium. The final, outermost layer is a second layer of pyrolytic carbon, 0.040 mm thick. This layer is intended to hold the whole microsphere together even through radiation induced dimension changes. It provides extra strength to the relatively brittle silicon carbide.

The TRISO fuel pebble design is not specific to the PBMR. It has been used before in other Prismatic High Temperature Gas Cooled Reactors (PHTGR) like the 330 MWe Fort St. Vrain reactor in Colorado, the 15 MWe research reactor in Jlich, Germany, and the 300 MWe demonstration reactor in Hamm-Uentro, Germany. It is also currently being used in a 10 MWth pebble bed core research reactor in China called the HTR-10. The PBMR fuel technologies are supplied by the Japanese company NFI, and the German company Nukem.

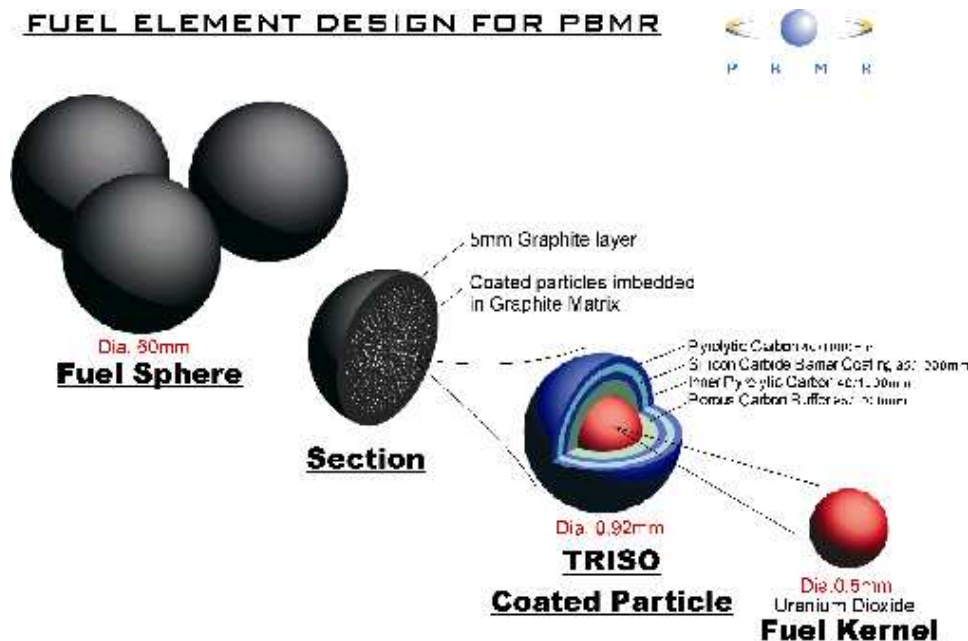


Figure A.10: PBMR Fuel (Source: [44])

A.2.2 Core Geometry

The Reactor Pressure Vessel (RPV) houses the Core Structure Assembly, parts of the refueling system, the Reactor Control System (RCS), the Reactor Shutdown System (RSS), and parts of the helium primary coolant system. It is 30 m long, and has an inside diameter of 6.2 m. It is made out of SA 508 Forgings, a low alloy, high-temperature and pressure ferritic steel, and weighs approximately 1,700 tons assembled. During normal operation the RPV reaches temperatures of $\sim 300^{\circ}\text{C}$ [44].

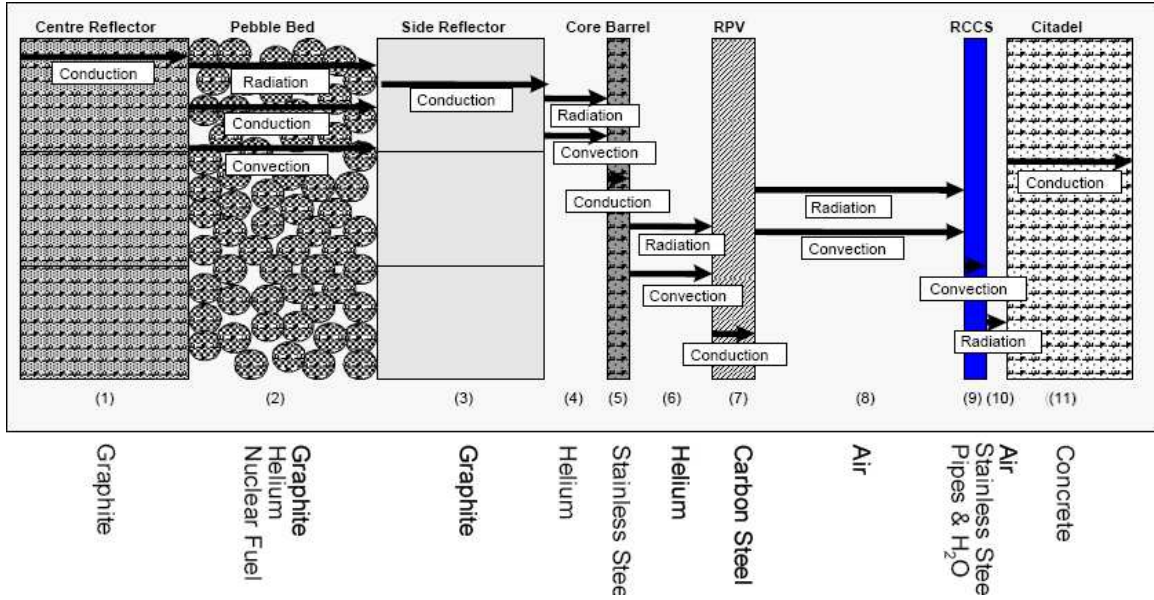


Figure A.13: PBMR Modularity (Source: [44])

A.2.3 Safety Systems/Reactivity Control

The graphite reflector plays an important role in the CSA since in addition to its role as reflector, it supports the fuel pebbles in the core, and houses reactivity control mechanisms. As shown in Figure A.13, there is an inner reflector, 2 m diameter, and an outer reflector. Inside the inner reflector are nine cylindrical tubes for the boronated control rods, and tubes for helium gas flow. The control rods are placed outside of the core to prevent fuel pebble damage during control rod movement. A second method of reactivity control is provided by an absorber ball system (RSS) in the outer reflector. These balls are 10 mm in diameter and when not in use are housed above the core barrel. When in use, they drop into one of 24 barrels in the outer reflector region [36].

The control rods in the inner reflector are used to control the PBMR power level. In addition, these rods stabilize the core temperature, and when needed can be fully inserted to bring the core to subcriticality. If an accident were to occur, gravity could lower these rods to the full in position within 13 seconds [36].

The absorber balls are used to compensate for reactivity changes after startup (from effects such as xenon buildup) and low power operation. They are sometimes used to aid in emergency shutdown. However, it takes over one minute for the balls to completely fill the outer reflector region. Returning the balls to the storage region also takes a long time, and thus they are only used to shut the reactor down when it operates at low power levels since less absorber balls are needed to bring the reactor subcritical from low power levels.

Unlike most reactors, these boronated absorbers are not the main form of reactivity

control. The PBMR depends heavily on the negative temperature coefficient to control the reactor power and reactivity levels. As the core temperature increases, the Doppler effect widens the uranium-238 neutron absorption resonances, and thus neutrons are lost to uranium-238 before they are able to fission uranium-235. By throttling the helium coolant flow rate we can control the Doppler effect, and thus control the fission rate/power levels.

The core structure of the PBMR is like no other reactor; there is no permanent fuel/coolant channel/control rod matrix.

A.2.4 Primary Coolant

At full power, the helium coolant flows through the core at an average of 120 kg/sec. [89] It enters the core at 500°C, and exits at around 900°C, at a pressure around 9 MPa. [44] The energy conversion uses a single phase closed Brayton Cycle. According to N. Todreas and M. Kazimi, Nuclear Science and Engineering Professors at MIT, the Brayton Cycle is “ideal for single-phase, steady-flow cycles with heat exchange and therefore is the basic cycle for modern gas turbine plants” [90].

Helium was chosen as the primary coolant for several reasons. First of all, it is a radiologically and chemically inert gas; it does not absorb fission neutrons and become activated, nor does it react with any of the other materials it encounters in its coolant cycle. Secondly, its thermodynamic qualities as a working fluid are much better than water; it has a higher thermal conductivity and larger specific heat capacity. For different working fluids at the same temperature, the fluid with the higher specific heat capacity can perform more work per mass. This means that the cycle pressure ratio is smaller, and the power density is larger. Therefore physical dimensions of the system can be smaller. Also, the heat exchanger can be smaller if the working fluid has a high thermal conductivity. [36]

A.2.5 Plant Size

The PBMR module building is 55 m tall; it rises to a height of 36 m above ground, and reaches a depth of 19 m below ground. It is 36.4 m wide, 62.9 m long, and composed of 40 MPa concrete. The module building mainly consists of the reactor unit, the power conversion unit, the helium coolant storage system, the refueling vessel, and the spent fuel storage tanks [44].

Since one PBMR only produces 400 MWth, much less than most single unit reactor systems, it was designed to exist in multi module systems. PBMR Ltd. prepared plans

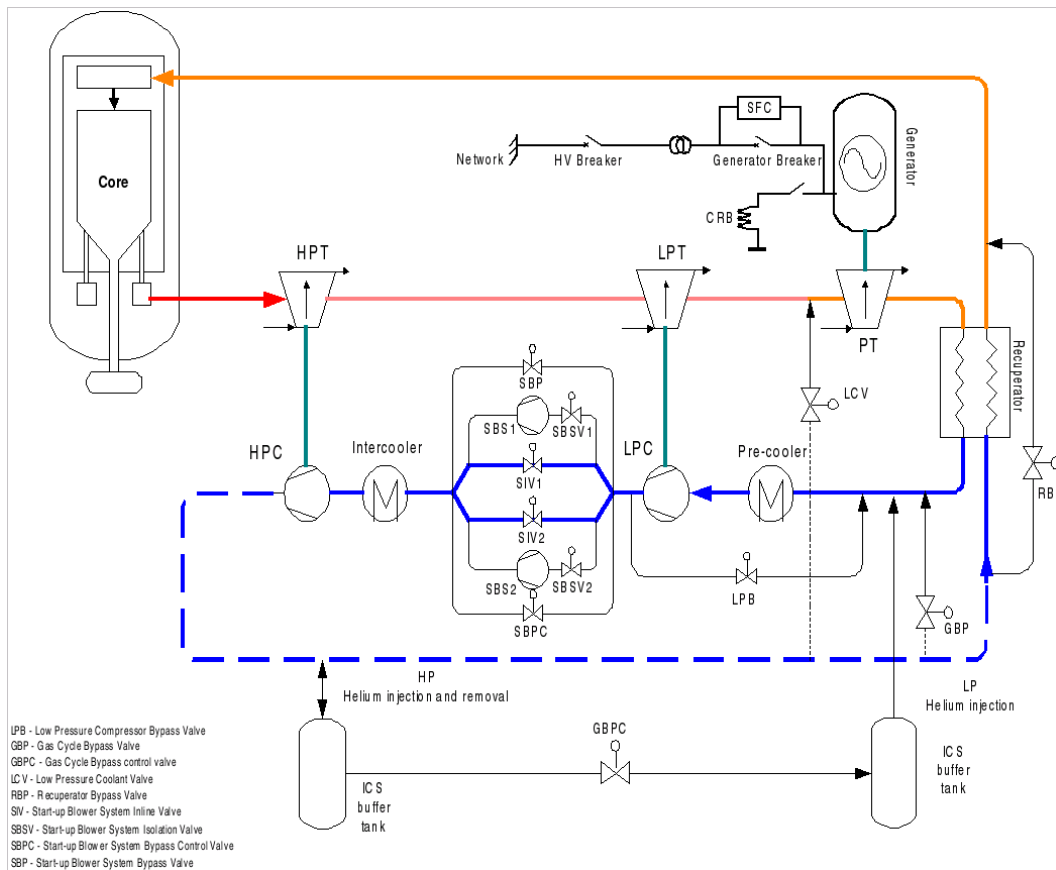


Figure A.14: PBMR Fluid Flow (Source: [44])

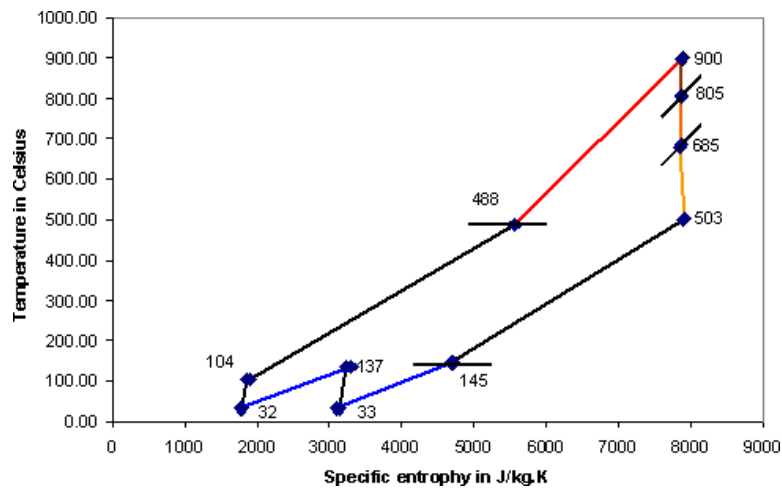


Figure A.15: PBMR Entropy Diagram (Source: [44])

for a single unit plant, 2-pack, 4-pack, and 8-pack power plant configurations. The 8-pack plant can produce up to 1,320 MWe. PBMR Ltd. boasts that even this, their largest plant, is more than twice as small as the typical 1,400 MWe PWR. They claim that the typical PWR is approximately 24,000 m², while the 8-pack PBMR plant is only 103 m wide and 113 m long, thus comprising an area of 11,639 m² [44].

A.2.6 Constructability

The PBMR consists of several small modules that can be assembled on-site in a “lego” style fashion, simplifying construction greatly. The secondary or balance of plant side, for instance, is made up of 21 modules of up to 2.4 m × 3.6 m × 18 m (8 ft × 12 ft × 60 ft) [91], which fit in the railway clearances as described in Section A.1.6.

However, the reactor vessel’s inner diameter is 6.2 m, so railway shipping of this component as a whole would not be a possibility. Other options, such as road transportation would need to be studied. Also, smaller module sizes with lower thermal power outputs and smaller reactor vessels should be considered.

A.2.7 Multi-unit PBMR Plant

As stated in Section A.2.5, the PBMR is fully prepared to exist in multi-unit systems since most applications would require more than 400 MWth. See Figure A.2.7 for a floor layout of an 8-unit plant. The lower thermal power rating gives the PBMR versatility to be usable and efficient for operations that demand lower powers. Also, it has been proposed that each unit would not have to run at variable powers to achieve the desired power level for the overall plant. Instead each unit could be run in either a full power “on” mode, or an off mode, and the number of units “on” would decide the overall power level. This system provides benefits since it is more difficult and less efficient to control reactors running at a fraction of full power.

In general, multi-unit reactor plants are more efficient than single unit systems because multi-unit plants can share several systems. A multi-module PBMR plant would share:

- Helium Inventory Storage
- Helium Purification System
- Helium Makeup
- Spent and Used Fuel Storage
- Graphite Storage HVAC blowers and chillers
- One remote shutdown room
- One Primary loop initial Clean-up system
- Fire protection reservoirs and pumps
- Generator Lube Oil System & Transformer (shared per 2 modules)

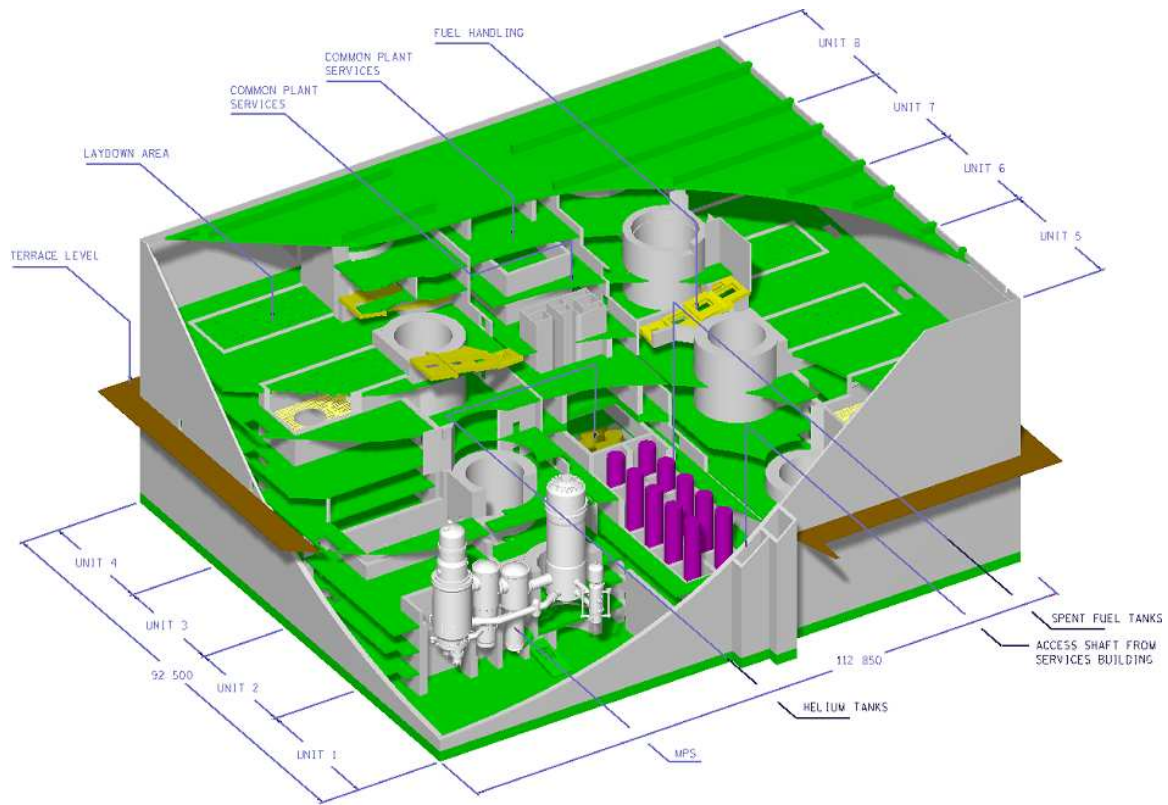


Figure A.16: PBMR Layout (Source: [44])

A.3 The Westinghouse AP600

A.3.1 Fuel Type

The fuel is usually enriched uranium, with 4.20% by weight uranium-235 and 0.04% by weight uranium-234, but can also be mixed oxide (MOX) fuel. A core loading consists of 66.90 metric tons of uranium. The cladding material is Zircaloy, a corrosion-resistant alloy made of around 98% by weight zirconium, with approximately 220 grams of cladding per kilogram of fuel [92]. The active fuel length is 144 inches (12 feet) and the outer diameter of each fuel rod is 0.374 inches [47].

A.3.2 Core Geometry

The core consists of 145 Vantage 5-H fuel assemblies of 264 rods of fuel pellets each, in 17×17 arrays, 45 control assemblies and 16 gray rod assemblies. The absorber material in the control rod assemblies is a silver-indium-cadmium (Ag-In-Cd) alloy, while that in the gray rod assemblies can be either the same one or 304 stainless steel. The core has an average linear power of 4.10 kW/ft [47].

This design is light-water moderated, and uses a steel radial neutron reflector, which

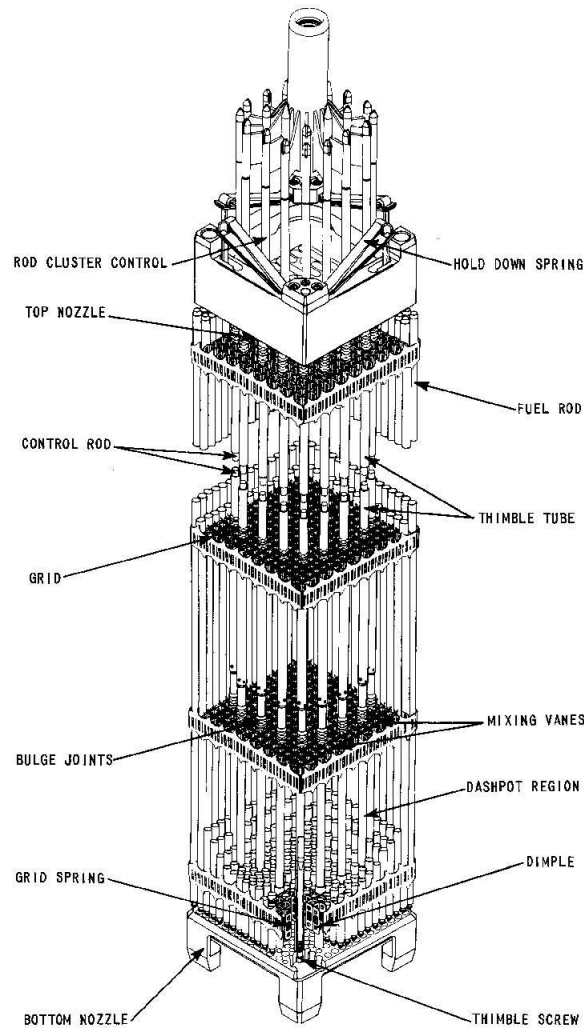


Figure A.17: Typical Westinghouse 17×17 fuel assembly (Source: [93])

surrounds the core. The 157-inch inner-diameter reactor vessel of the AP600 would be made of forged rings instead of welded plates. It would have two hot leg nozzles and four cold leg nozzles, of 31.0 and 22.0-inch diameters respectively, as well as two safety injection nozzles. The vessel is designed for a fluence of 2.0×10^{19} neutrons per cm^2 [47].

A.3.3 Safety Systems/Reactivity Control

This design relies on passive safety systems for emergency reactor and containment cooling. It uses natural driving forces, such as gravity, natural circulation, convection, evaporation and condensation, such that no operator action is required for 72 hours in case of an accident. No active components like pumps or fans are used in the safety systems, and no safety-grade support systems are required.

The emergency core cooling system provides core residual heat removal, safety injection and depressurization, and is located entirely inside the steel containment vessel, so that

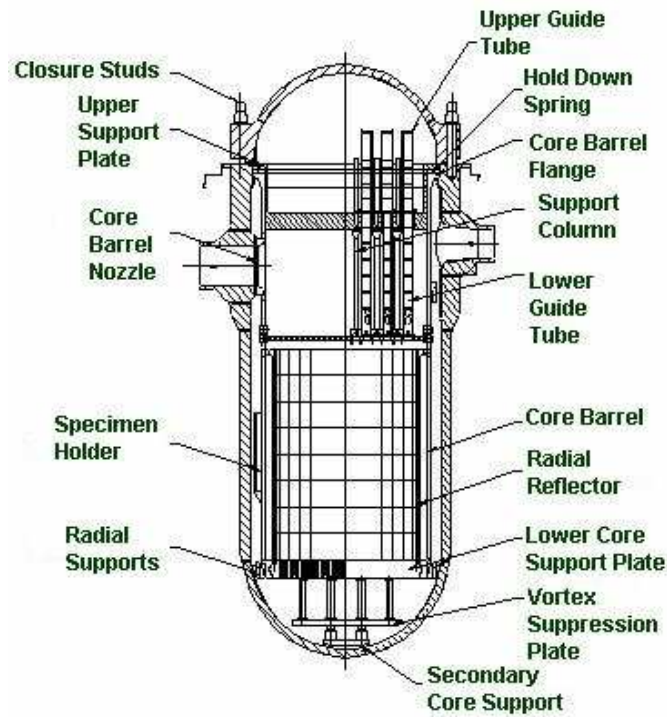


Figure A.18: AP600 Reactor Vessel (Source: [48])

circulating reactor coolant outside the building is unnecessary.

Two accumulator tanks under nitrogen pressure, 4.8 MPa(g), and two core makeup tanks of 2,000 ft³ each provide safety injection. Gravity drain of water from a 530,000 gal in-containment refueling water storage tank (IRWST) suspended above the level of the core supplements the other cooling water sources. There is no need for high-head or low-head pumps, or for a boron injection tank [47].

In the case of a loss of cooling accident (LOCA), natural circulation air-cooling and evaporation of water flowing from the suspended tank combine so that heat is continuously removed, and pressure is reduced.

There are two normal residual heat removal pumps, each operating at a pressure of 6.21 MPa(g) a flow rate of 1,000 gallons per minute, as well as two component-cooling water pumps and two service water pumps.

The auxiliary feedwater includes two motor pumps, each with a flow rate of 380 gallons per minute, and a 100% capacity passive residual heat removal heat exchanger, at a heat removal rate of 42 MW, satisfying safety criteria for feedwater accidents and steam line breaks [47].

The electrical systems include two 4,000 kW diesel generators, apart from the Class 1E batteries of a total capacity of 28,000 amp-hours, which supply all the power requirements for safety systems, making safety-grade on-site AC power unnecessary.

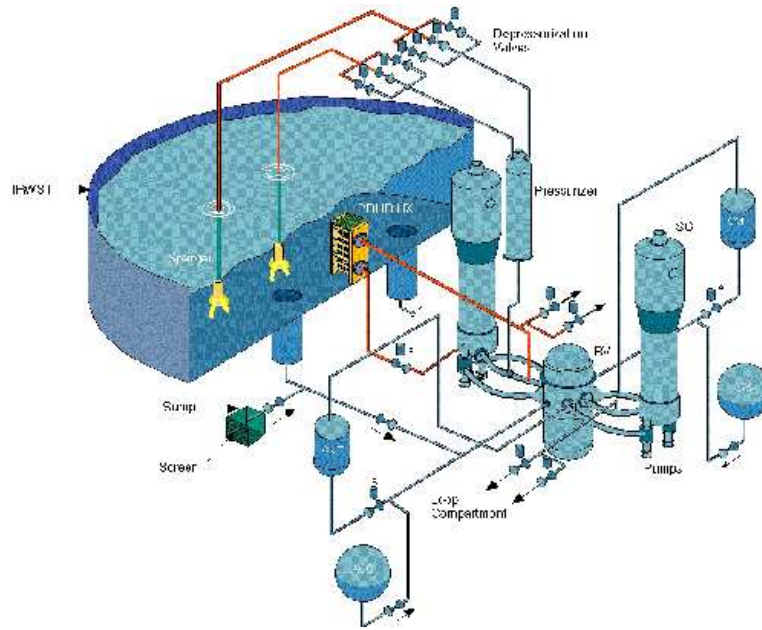


Figure A.19: AP600 Passive core cooling system (Source: [48])

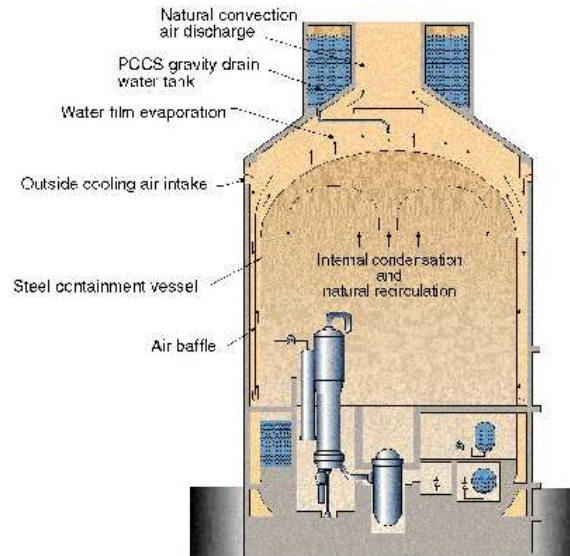


Figure A.20: AP600 Containment cooling system (Source: [48])

Probabilistic Risk Assessment (PRA) studies predict a core damage frequency of 2.6×10^{-7} per year and a large release frequency of 3.3×10^{-8} per year for the AP600, each around three orders of magnitude smaller than currently operating plants [47].

A.3.4 Primary Coolant

The design uses four high-inertia, canned-motor pumps, rated at 3,500 hp each, to circulate reactor-cooling light-water through the core and the steam generators at 51,000 gallons per minute. Two pumps are located in the channel head of each steam generator.

The hot leg temperature is 316°F [47].

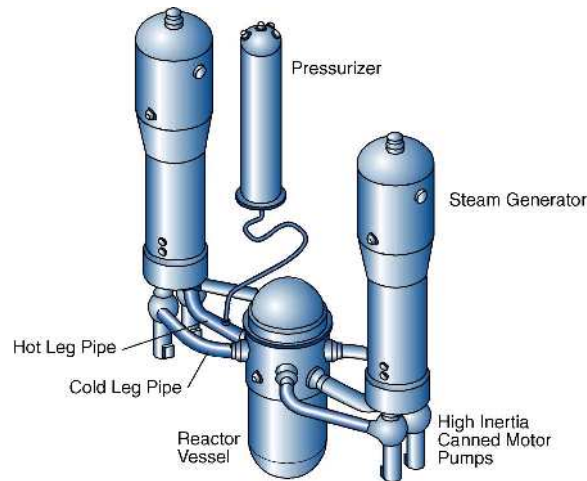


Figure A.21: AP600 Reactor cooling system (Source: [48])

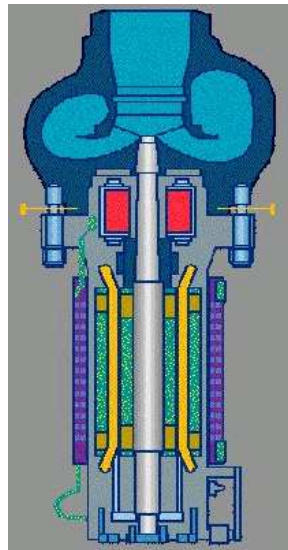


Figure A.22: AP600 Reactor coolant pump (Source: [48])

A.3.5 Plant Size

The steel containment vessel has a 130 ft inner diameter and it has an elevation of 308 feet and 3 inches. It has a volume of $1.76 \times 10^{-6} \text{ ft}^3$ and a design pressure of 310 kPa(g). The shell is very thin: 1.625 inches thick for most of the containment and 1.75 inches for the bottom cylindrical section [47].

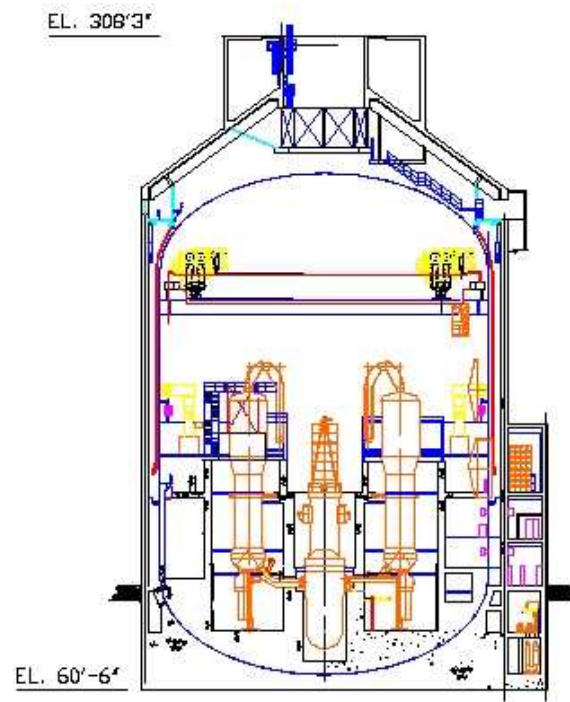


Figure A.23: AP600 Containment Cross-section (Source: [94])



Figure A.24: AP600 Nuclear island footprint/plan (Source: [94])

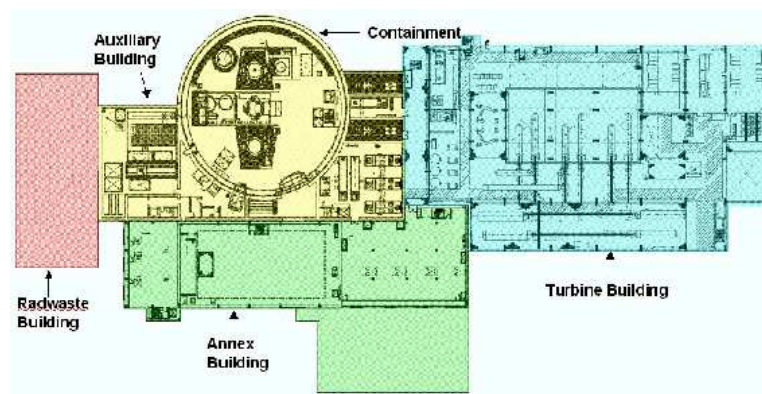


Figure A.25: AP600 single-unit plant (Source: [95])

A.3.6 Constructability

Thanks to modular construction techniques and new features, the construction time and costs are minimized. The AP600 requires 50% fewer valves, 35% fewer pumps, 80% less piping, 80% fewer heating, ventilation and cooling (HVAC) units, 45% less seismic building volume and 70% less cable than a typical 600 MWe plant in operation. This and other simplifications shorten the construction time by simplifying the overall arrangement. Construction is expected to take between 32 and 36 months, which, together with pre-construction and start-up activities, would add up to a total of 60 months from the plant order to the start of operations [47].

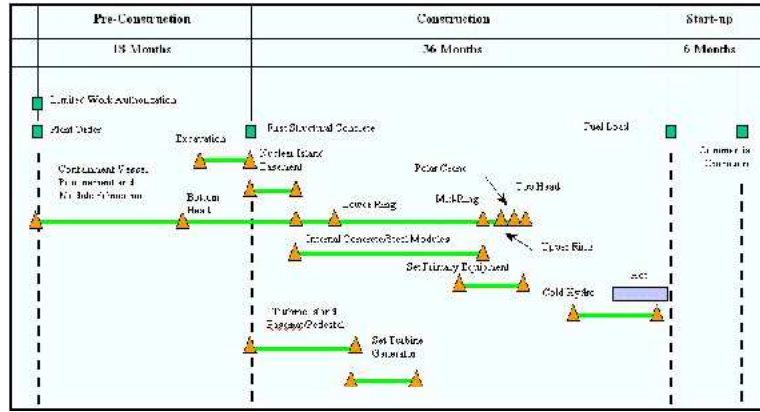


Figure A.26: Overall 60-month schedule for a standardized AP600 plant (Source: [95])

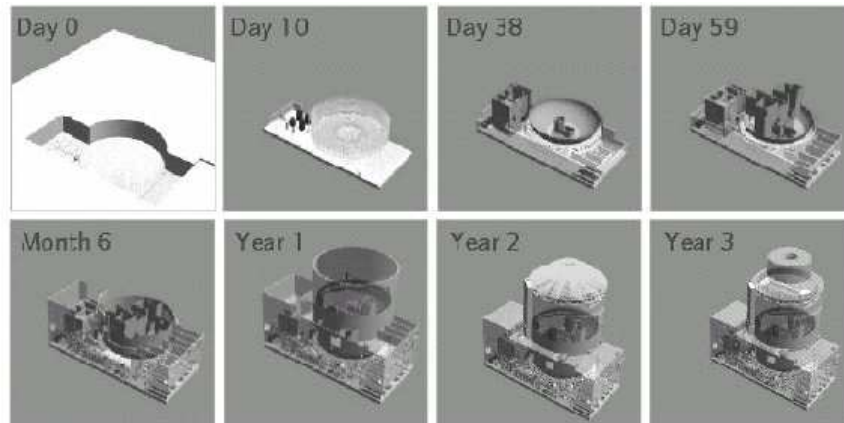


Figure A.27: 36-month AP600 construction sequence (Source: [96])

Modularization permits repetitive construction activities, an accelerated learning curve and a large reduction in field labor for parallel tasks. This shortens the overall schedule and potentially reduces costs for Nth-of-a-kind plants. The AP600 consists of 250 rail-shippable and 50 large structural modules. These can be centrally manufactured and pre-tested, and assembled onsite [97]. The main structural module is T-shaped, with dimensions 15 m \times 18 m \times 20 m, which can be rail-shipped in submodules of up to 3.7 m \times 3.7 m \times 25 m (12.3 ft \times 12.3 ft \times 83.3 ft) and up to 73 metric tonnes [96]. Shipping

these submodules is feasible, since, as outlined in Section A.1.6, existing rail lines to the sites have enough horizontal clearance for these dimensions.

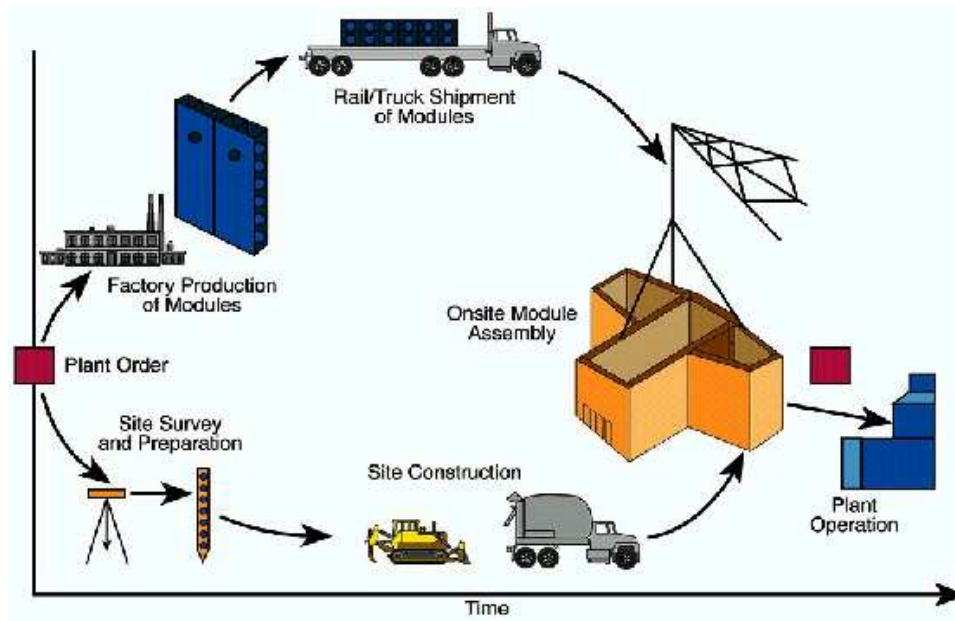


Figure A.28: Parallel tasks using modularization (Source: [95])

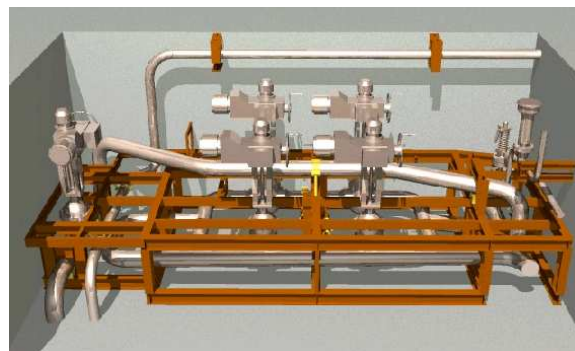


Figure A.29: Typical AP600 piping and valve module (Source: [48])

A.3.7 Two-Unit AP600 Plant for Power Increase

As with the ACR-700, the AP600 plant can consist of two units in case more power than that provided by one unit is needed. However, in this case, the units would not share any systems and would be completely independent. Costs per unit energy output would still decrease due to “common construction infrastructure and learning efficiencies” [75].

Appendix B

Other Reactor Designs

B.1 All Reactor Types that were considered.

We initially researched ten reactors designs for their suitability as an energy source for the oil sands. These include: boiling-water reactor, gas-cooled fast reactor, high temperature gas-cooled reactor, liquid-metal fast-breeder reactor, light water breeder reactor, molten salt breeder reactor, pressure-tube graphite reactor, pressurized heavy-water reactor, pressurized-water reactor, and spectral-shift converter reactor. Of these we chose: high temperature gas-cooled reactor, pressurized heavy-water reactor, and the pressurized-water reactor because these reactor designs were the most fitting when analyzing the cost, licensability, constructability, and safety of each reactor design.

B.2 Boiling Water Reactor (BWR)

One of the first reactor designs considered was the BWR, which has been operating commercially since 1960 with units in countries such as Italy, Germany, Netherlands, India, Japan, and Spain. The BWR is placed into the family of light water-reactor reactor because it uses water as its coolant and moderator. Unlike most other reactor designs, the BWR has only one loop in its steam cycle. The BWR The reference reactor in Table A2.1 is the BWR/6 which is manufactured by General Electric. The BWR/6 has a gross thermal power of 3,579 MWth, net electrical power of 1,179 MWe, and operates with an efficiency of 32.9% [93].

The BWR was also one of the first reactor designs to be eliminated. An environmental liability existed by not having the primary loop from the steam cycle isolated. Water would be going from the radioactive core straight to the ground for SAGD. The idea

to isolate the primary loop by adding a heat exchanger and a secondary system was discussed, but was dismissed because we would then be working with a pressurized-water reactor.

B.3 Pressure Tube Graphite Reactor (PTGR)

The PTGR was invented in the Soviet Union. One of the most popular PTGR models was the RBMK-1000 which is the referenced model in Table A2.1. The PTGR uses light water as a coolant and graphite as a moderator. The reactor was originally designed to produce plutonium and electricity. The RBMK-1000 has a gross thermal power of 3,200 MWth, net electrical power of 950 MWe, and efficiency of 31.2%. The fuel used for the RBMK-1000 is UO_2 , with 1.1–2.4% by weight uranium-235 [93].

The PTGR was not chosen because the licensing would be difficult to attain because the reactor at the Chernobyl-4 site was a PTGR. There has only been one PTGR licensed in North America, which was the Hanford-N unit and it was shutdown right after the Chernobyl-4 accident. In addition the reactor only has one steam cycle loop which would not be environmentally safe for the same reasons explained for the BWR.

B.4 Spectral Shift Converter Reactor (SSCR)

The SSCR (spectral shift converter reactor) is based on light-water reactor and pressurized-water reactor technologies. The referenced reactor SSCR model in Table A2.1 is the RCVS which is developed by FRAMATOME. The reactor operates by shifting the neutron spectrum upward from the normal thermal energies. The RCVS operates with a gross thermal power of 4,200 MWth. A benefit of the SSCR is the potential to save about 10–30% in uranium feed requirements. The fuel used in the RCVS model is either 4.2% by weight uranium-235 or 6% by weight fissile plutonium enrichment [98].

The SSCR was not chosen because there has been minimal progress done in recent years. We felt that the SSCR design did not hold significant advantages for the oil sands application in terms of cost, licensability, constructability, and safety.

B.5 Gas Cooled Fast Reactor (GCFR)

The GCFR is also known as a gas-cooled fast-breeder reactor. Research has been done since the 1960's, but there has yet to be a commercially operational GCFR. The GCFR

uses a closed fuel cycle. The GCFR is able to produce hydrogen which would be beneficial for the SAGD in the oil sands. General Atomics has been a principal supporter of the GCFR. The GT-MHR is the current design General Atomics is working on. The GT-MHR has an efficiency of close to 50% while producing 50% less high level waste than current commercial reactors [99]. The reference in reactor in Table A2.1 is an 800 MWth model. The fuel in the referenced reactor consists of UPuC/SiC (70/30%) with ~20% Pu content as the fuel [100]. The coolant on most designs of GCFR is helium (i.e. GT-MHR and referenced reactor), but some use CO₂ and the moderator is zirconium hydrate [99].

The GCFR reactor was eliminated because it was too experimental. Though it has clear safety and cost advantages over other reactors, the amount of R&D needed to ensure a successful operating commercial plant was costly and not within our time frame.

B.6 Light Water Breeder Reactor (LWBR)

The LWBR is a thorium breeder that uses water as a coolant and moderator. The fuel used was 6% by weight UO₂-233 in ThO₂. The LWBR is meant to be the same size as a light-water reactor. The referenced reactor in Table A2.1 is a 60 MWe Shippingport experiment [93].

The LWBR ended up being too experimental to choose for the oil sands application. The R&D required to successfully implement a LWBR was not worth the wait and cost.

B.7 Liquid Metal Fast Breeder Reactor (LMFBR)

The LMFBR has been commercially successful in France. The LMFBR design first produced electricity in 1952. The referenced reactor in Table A2.1 is the Superphenix which is manufactured by Novatome. It uses a UO₂/PuO₂ for fuel and liquid sodium as a coolant. The core is designed to be small which makes the reactor easier to transport and relocate if needed. The efficiency of the plant is 40%. The gross thermal power is 3,000 MWth and the net electrical power is 1,200 MWe [93].

The LMFBR was not chosen because it was more costly to operate than the pressurized-water reactor, pressurized-heavy water reactor, and the high temperature gas-cooled reactor. The reactor can be as much as 50% more expensive to maintain than light water reactors. Being a breeder reactor the LMFBR would be more difficult to license than the converter reactors.

B.8 Molten Salt Breeder Reactor (MSBR)

The MSBR uses a molten salt mixture as a coolant. It has a gross thermal power ranging from 2,250 MWth to 4,500 MWth. The net electrical power ranges from 1,000 MWe to 2,000 MWe. The MSBR uses lithium-7, beryllium, zirconium, and a uranium mixture as its fuel. It is 44% efficient and it does not produce any long lived actinides in its waste [93].

The MSBR was not chosen because it was also too experimental making the research and development needed too costly. The MSBR did not present any clear advantages over the chosen reactors that would warrant the R&D needed.

B.9 Reactor Designs Eliminated; at a glance

Attribute	PTGR	SSCV	GCFR	LWBR
Core Outlet Operating Temperature Range (°C)	284	—	850	Similar to 60 MW PWR
Thermal & Electric Power Capability	3,200 MWth / 950 MWe	4,250 MWt	600 MWth / 288 MWe	60 MWe
Steam Pressures	—	2,250 psi	—	Similar to 60 MW PWR
Fuel Type	UO ₂ , 1.1–2.4% by weight U-235: 1.8–2.0% for the RBMK designs	4.2% by weight U-235 or 6% by weight fissile plutonium enrichment	UPuC/SiC (70/30%) with ~20% Pu content	6% by weight UO ₂ -233 in ThO ₂
Coolant Type	H ₂ O	—	Leaning towards helium, but also looking into CO ₂ and N ₂ O ₄	H ₂ O
Moderator Type	Graphite	—	Zirconium Hydride was suggested	H ₂ O
Reactivity Control Mechanisms	One of the most complex, uses control rods, B ₄ C as an absorber material	Based on heavy water for PWR model	Control rods bear resemblance to LMFBR system	—
Refueling	Online Refueling	—	—	No refueling during lifetime

Table B.1: Reactor Characteristics Comparison: Part I

Attribute	LMFBR	MSBR	BWR
Core Outlet Operating Temperature Range (°C)	54 at Core Outlet, 487 at SG	565–704	288
Thermal & Electric Power Capability	40 MWth(FBTR, India) – 2,900 MWth (Superphenix, France), 15 MWe (FBTR) 1,200 MWe (Superphenix)	2,250–4,500 MWth, 1,000-2,000 MWe 44% efficiency	3,759 MWth, 1,178 MWe
Steam Pressures	0.1 MPa at Core Outlet, 17.7 MPa at secondary outlet boundary	Liquid salt in the primary has less than 0.1 torr, Secondary 3,500 psi at 537°C	1,000 psi
Fuel Type	UO ₂ /PuO ₂	Li-7, Be Zirconium, U mixture	UO ₂
Coolant Type	Liquid Na	Molten Salt Mixture, without Uranium or Zirconium, Many fluorides	H ₂ O
Moderator Type	None	Graphite Doubling time is 13–20 years	H ₂ O
Reactivity Control Mechanisms	Hexagonal bundles of B ₄ C	Control Rods	Cruciform geometry, B ₄ C pins
Refueling	Variable refueling sequence, ~32 day outage time	Online Refueling	Similar to PWR

Table B.2: Reactor Characteristics Comparison: Part II

Attribute	PTGR	SSCV	GCFR	LWBR
Manufacturing Companies	—	FRAMATOME: RCVS	General Atomics' only implementation was at Shippingport 60 MWe nuclear power station	Novatome
Number of Commercial Units / Licenseability	Hanford-N began operating commercially in 1966 shutdown after Chernobyl, Soviets have many more than US	—	0 commercial Units worldwide	0 commercial units, difficult to license
Special Considerations?	Steam Cycle has only one loop RBMK model is the most typical; Soviet design; 26 operating reactors of this type worldwide as of 1991	Based on LWR and PWR technology	Thorium breeder; needs reprocessing; too experimental	40% Thermal efficiency; one of the world's most studied concepts; expensive, no need for breeders.

Table B.3: Current Status of Reactor Designs: Part I

Attribute	LMFBR	MSBR	BWR
Manufacturing Companies	—	—	General Electric
Number of Commercial Units / Licenseability	5 operating in France, Japan, Kazakhstan, Russia	0 commercial units in US	GE model operating in 8 countries
Special Considerations?	Viscosity at reactor operating temperature is that of kerosene; salts melt at 435°C; revived interest in using liquid salt as a coolant	Has one loop in its steam cycle	—

Table B.4: Current Status of Reactor Designs: Part II

Appendix C

More Information on Natural Gas

C.1 Canadian Supply of Natural Gas

Natural Gas is supplied from three major sites in Canada: Western Canadian Sedimentary Basin (WCSB), the East Coast, and the Mackenzie Delta. The WCSB is a major source of the current natural gas supply, with an estimated one half of Canada's natural gas supply. Approximately half of the supply from WCSB has been produced [28]. Wells are being drilled deeper and more frequently, but natural gas production from the WCSB has leveled out at about 16 bcf/day, showing that this source is maturing [24]. The offshore east coast resource is supposed to be large, but few drilling efforts have been successful in producing oil. Production from the offshore east coast resource is estimated to remain at 400 to 600 mmcf/d (million cubic feet/day). The McCully field in New Brunswick is promising and access to the Maritimes and Northeast Pipeline system and larger markets would ensure more investment to develop this site. The Mackenzie Delta will contribute to Canada's natural gas production by 2010 [24]. Figure C.1 shows Canadian natural gas reserves.

C.2 Unconventional Natural Gas Deposits

Unconventional natural gas development has not been fully explored. Frontier areas are one of the untapped natural gas resources. Many sites are in remote locations that are not expected to produce significant amounts of natural gas, making these projects economically unfeasible [28].

Gas hydrates, shale gas, and coal bed methane are Canada's three unconventional natural gas resources. Gas hydrates are methane molecules surrounded by ice molecules found

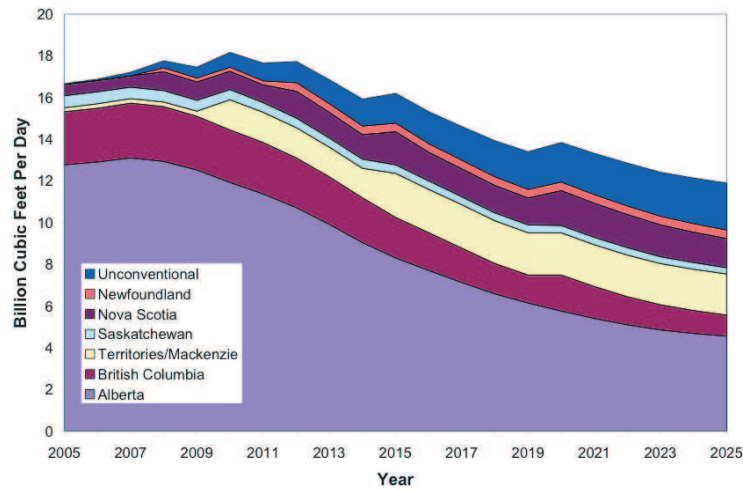


Figure C.1: Canadian Natural Gas Reserves

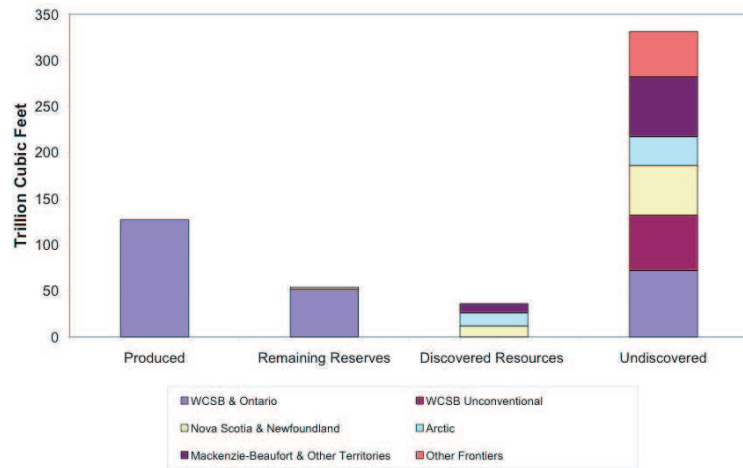


Figure C.2: Canadian Natural Gas Supply

on or under ocean bottoms and on land in permafrost areas. There has been little exploration of extraction and processing techniques; therefore it is unlikely these deposits will be used as a source of natural gas within the next 20 years. Shale gas is the methane that has adsorbed into the organic matter in shale. In Western Canada, several high organic shale deposits are proposed to be shale gas deposits. The ease of extraction, reduction of pressure, and availability of shale deposits prove shale gas as potentially an unconventional source of natural gas. Coal bed methane is an abundant source of methane adsorbed onto the internal surface area of coal, found wherever coal is found. Like shale gas, coal bed methane can be released by reducing pressure. Coal bed methane was the first commercialized source of unconventional natural gas in Canada and the US [28]. In 2004, about 1,000 coal bed methane wells were drilled with production estimated at 100 mmcf/day [2].

C.3 Emission Trading

Part of the Government's plan includes the trading between companies of emissions "credits." Companies would be required to own permits to cover their emissions, a majority of which would be given for free based on the companies current emissions intensity and production, and the remaining having to be either earned by proven emissions reductions investments or purchased from companies with a surplus of permits [12]. Companies that have lower emissions intensity to begin with would not need extra permits and could sell some of theirs. The idea is to give monetary incentive to reduce emissions. There is concern, however, that further intermediate targets could be implemented by the government before 2012, and that revising the permit policy in a fair manner to account for this would be difficult. Also, some sources believe that the 2012 goal is too narrow a time frame for companies to implement technologies to reduce emissions, so the Government is thinking of accepting a pre-approved plan of future long-term emissions reductions in place of proven immediate reduction technologies.

C.4 CO₂ Sequestration

The most promising technology for emissions reduction in the oil sands industry is CO₂ sequestration. When CO₂ is produced in more concentrated forms (such as the production of hydrogen), sequestration is possible [35].

The most expensive CO₂ sequestration method is storage in depleted oil reservoirs, and is known as benign storage. Estimates provide that 100 megatonnes of CO₂ could be stored in the largest reservoirs for 90 years, but at a cost of \$75 per tonne, or \$4 per barrel.

CO₂ could also be used for enhanced oil recovery (EOR), or coal bed methane production (CBM), which put it to use. It can also be stored in deep aquifers. Figure C.3 shows the capacity for various storage methods, which in total could potentially store 100 megatonnes per year for 300 years, provided methods are found to make the cost of sequestration less prohibitive.

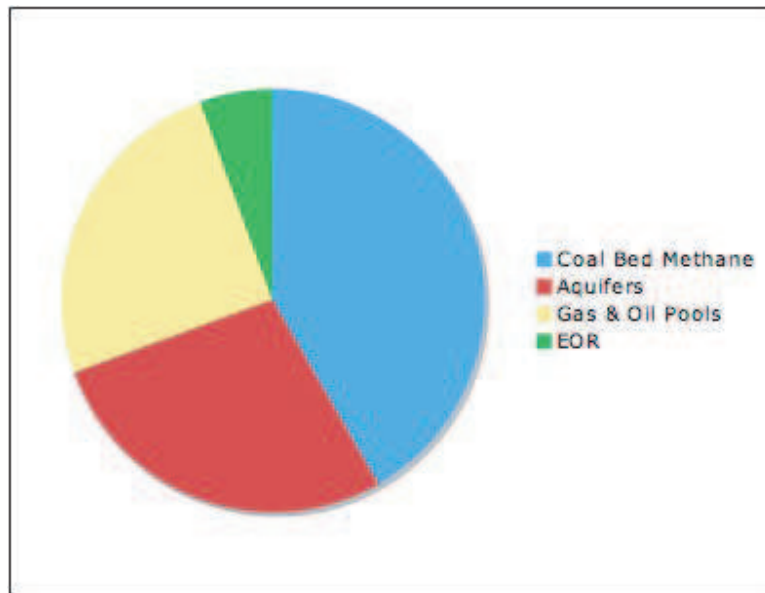


Figure C.3: Estimated CO₂ storage capacity (Adapted : [25])

Appendix D

Steam Assisted Gravity Drainage

D.1 SAGD Extraction

In steam-assisted gravity drainage (SAGD), a horizontal production well is drilled into the base of the oil sand formation. A steam injection well is drilled above this production well and high temperature and pressure steam is injected into the tar sand. As the oil sands are heated, the viscosity of the bitumen decreases, and a high temperature pressure chamber is formed around the injection well. The steam rises to the top and sides, condensing throughout, expanding the chamber size and liquefying more bitumen. Gravity pulls bitumen and heavier condensates down toward the production well, as shown in Figure D.1 [1].

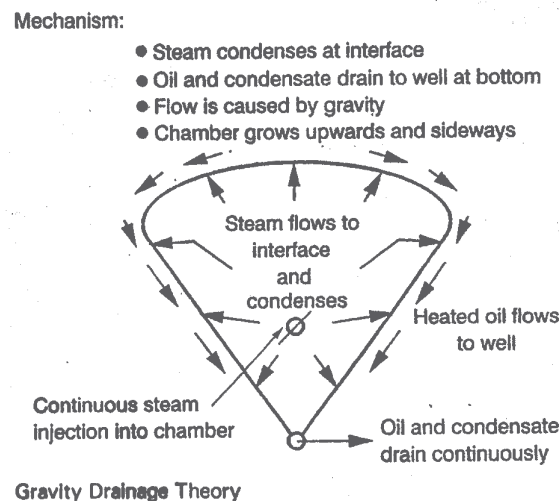


Figure D.1: Steam Assisted Gravity Drainage (Source [1])

D.1.1 Chamber Formation

As steam is continually injected into the ground, the size of the liquid filled chamber, described in the previous paragraph, grows as shown in Figure D.2.

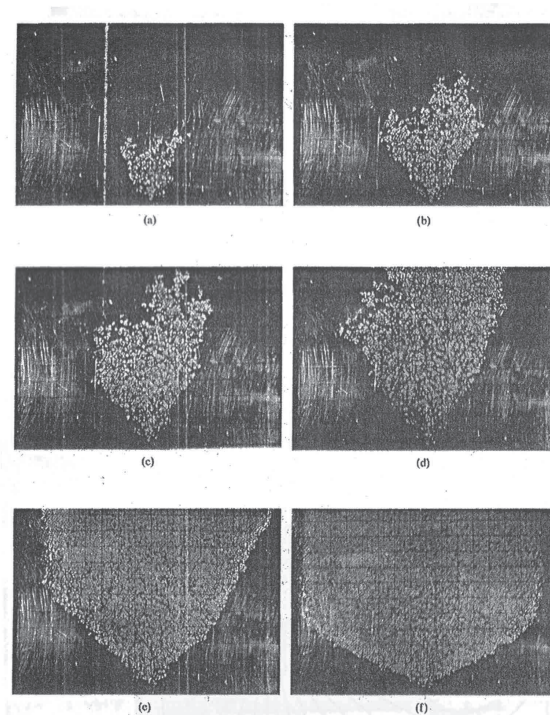


Figure D.2: Development of the Steam Chamber During Gravity Drainage in Laboratory Model (Source [1])

With time, the chamber expands horizontally into neighboring chambers and then downward, covering nearly all of the target area as illustrated in Figure D.3 [1].

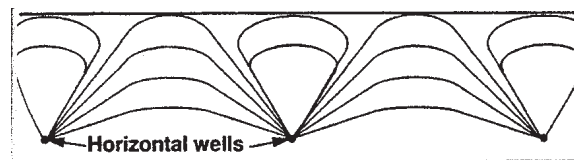


Figure D.3: Growth of Steam Chambers Above Parallel Adjacent Horizontal Wells (Source [1])

After approximately 60 days of steam-injection heating, the chambers formed will have a radius of approximately three to five meters. The vertical distance required between the production well and the horizontal steam injection well, to allow for a one-year chamber breakthrough between the two wells, is a function of bitumen viscosity [1]. Typically, the horizontal injection wells are placed approximately two meters above and parallel to production wells.

For bitumen, with a viscosity between 100,000 and 1,000,000 cp, the required distance between the two wells for a one-year breakthrough time is approximately one to five

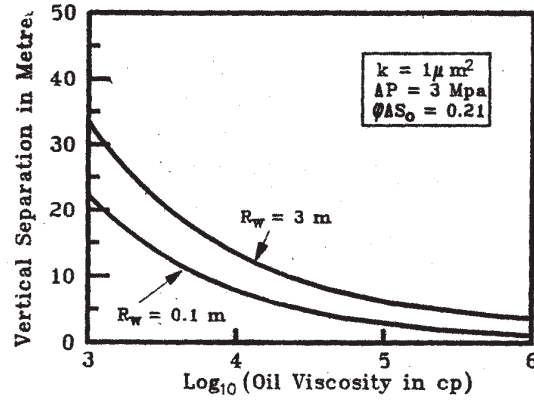


Figure D.4: Vertical Separation of Oil Wells (Source [1])

meters, as shown in Figure D.4 [1]. Separations of less than two meters are preferred [101].

Modeling the steam chamber interface is a valuable tool both in the understanding of the production and a means of maximizing the specific site's production. The chamber development is described by three parameters: horizontal chamber interface, x , vertical chamber interface, y , and the height of the chamber, h .

The height of the chamber is the simplest of these parameters. The height is merely a function of a geometrical constant, reservoir and oil properties, and time. It does not depend on the other two parameters, x and y , thus easing its calculation. [1]

The chamber height (h) is a valuable tool because it provides good estimates of the area processed (A). The chamber shape does not change dramatically as the chamber increases in size. Thus the chamber height can be thought of as a characteristic diameter of the chamber geometry.

$$A = \gamma h^2 \quad (D.1)$$

The constant gamma is a scaling factor for the area based off the characteristic diameter of the chamber. This value can be approximated either experimentally or using the interface parameters that will be discussed shortly. Since the chamber height is a function of time, the area of the chamber can be written as a function of time also.

Although the chamber height does give great insights into the area of the chamber, much experimental work is necessary to provide the value of γ necessary for the calculation unless the development of the chamber interfaces is modeled. The advantage of modeling the chamber interfaces is that through knowing the time development of the interfaces,

one can predict the location of the chamber resulting from one well to another. By properly managing the location of these wells, production over various periods of time at a particular site can be maximized. The complexity in the calculation of the interfaces is that they are dependent on each other.

A model showing the steam-bitumen interface shape (and thus the chamber shape) between the injection well and the corresponding production well prior to the breakthrough time is shown in Figure D.5 [1].

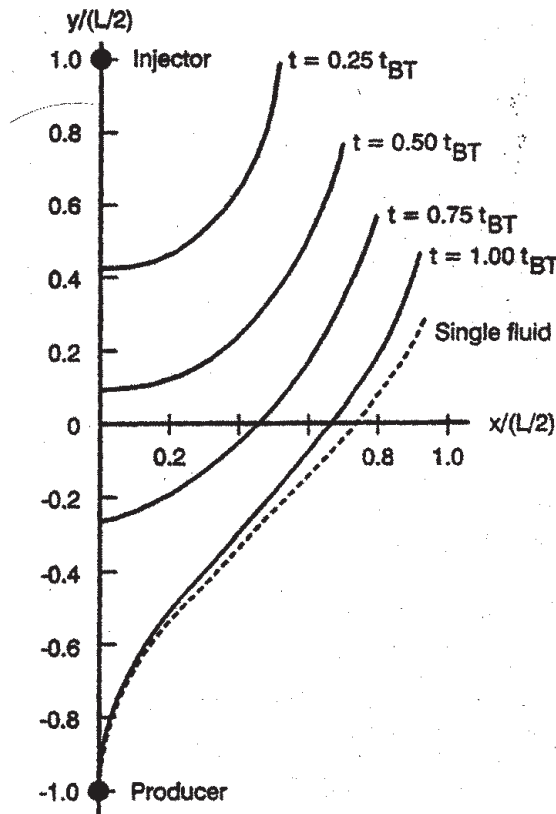


Figure D.5: Positions of Steam Front (Source [1])

SAGD is an especially useful extraction technique in areas such as Alberta, since large water reservoirs are located directly beneath the target area and the chamber will cease to expand downwards following breakthrough. In addition, SAGD allows for the pressure in the chamber to be controlled in such a way as to match that of the water reservoir below, allowing for less water entering the production well drainage site [1].

D.1.2 Chamber Drainage

The flow rate of oil obtained through SAGD of the aforementioned chambers is independent of the horizontal length of these chambers, and is instead dependent upon chamber

height. Once the chamber formed reaches its maximum height, increases in oil production due to increased surface area are offset by the distance the oil has to travel to reach the production well. This can be attributed to the increasingly steep-sloped chamber walls. While the chamber is being created, bitumen drainage to the bottom of the forming chamber may prevent the injected steam from advancing the chamber further toward the production well. The chamber itself is by no means at a constant temperature along its entirety, with the bitumen along the walls surrounding the injection site at a higher temperature than the bitumen located along the bottom of the expanding chamber. One solution to this is to inject the steam at a higher pressure than the draining bitumen [1].

One of the benefits of SAGD, as mentioned in Section 3.2, is the comparatively low volume of water necessary to extract the bitumen. However, this value changes over the lifetime of a given well. As more bitumen is extracted, it becomes increasingly difficult to remove, and requires more water to withdraw the equivalent volume of bitumen. The process uses a water to bitumen ratio between two and three, with two as a lower bound for a high performance well, and three as an upper bound for a low performance well. When the ratio rises above three, the well is no longer economical, although bitumen is still recoverable.

The steam specifications of the system depend on the pressure and saturation temperature of the steam. Most of the energy stored in the steam and transferred from the steam to the bitumen in the SAGD system is in the enthalpy of vaporization, the energy stored in the phase change from liquid to gas. It is possible to superheat the system steam before inserting it into the well, but this option fails to be advantageous for a number of reasons. The rationale behind this loss is that most of the energy is stored in the enthalpy of vaporization, so the extra degrees added by the superheating would be quickly lost through conduction, bringing the temperature of the steam back to that of saturated steam almost as soon as it comes into contact with the chamber. Additionally, to make the superheating process worthwhile, the mass flow would have to be increased significantly, creating a much higher water to bitumen ratio. Once this mixture is extracted from the ground, the water must be boiled off to retain the bitumen. In the boiling process, any energy gain arising from superheating is lost in the energy used to boil the water.

The drainage rate is directly dependent on steam temperature, as higher temperature steam will transfer greater heat to the surrounding bitumen [1]. The viscosity of the bitumen will decrease as the temperature is increased. Predicted drainage rates for several crude mixtures, including Athabasca bitumen is given in Figure D.6.

In practice, yield values of about 80% of this maximum rate are achievable [1].

By restricting the temperature to the saturation temperature, the only way to vary the temperature while maintaining the saturated state is to vary the pressure. However,

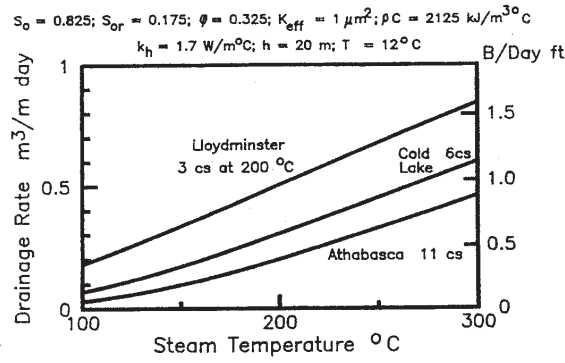


Figure D.6: Predicted Drainage Rates for Various Crudes (Source [1])

there are limits to the effectiveness of increasing the temperature and pressure. Holding other variables constant, there is a negligible difference in recovery rates between 1 and 6 MPa of pressure. The higher pressures, and thus higher temperatures, are accompanied by higher drainage rates. As a result, the bitumen softens faster and the viscosity is effectively lowered so that it can be extracted. Also, since the bitumen moves faster, the thermal efficiency is also improved because there is less heat lost to the overburden (the sand, rock, and clay above the oil sand deposits) and the reservoir outside the steam chamber. However, the gains from increasing the pressure are negated almost exactly by the losses from having to raise the steam temperature to that higher temperature. As a result, the oil-steam ratios are virtually independent of the pressure involved in the process.

After the chambers reach the maximum size, drainage ensues (in the case of Cold Lake crude) for approximately 2000 days [1]. For a steam chamber at a temperature of 216°C and Cold Lake crude oil, the residual oil saturation is shown in Table D.1.

Time (days)	Oil Saturation
100	0.34
200	0.26
1000	0.14
2000	0.10
10000	0.06

Table D.1: Residual Oil Saturation (Source [1])

Maximum production rate occurs when the chamber reaches maximum height and after breakthrough, and it decreases thereafter as the heated bitumen is processed from the target area [1]. No production will be observed prior to breakthrough. The expected production rate of a two-sided steam injection chamber as a function of the total oil remaining in the target area for a model oil sand target is shown in Figure D.7.

Oil production usually continues after the cessation of steam injection into the chamber.

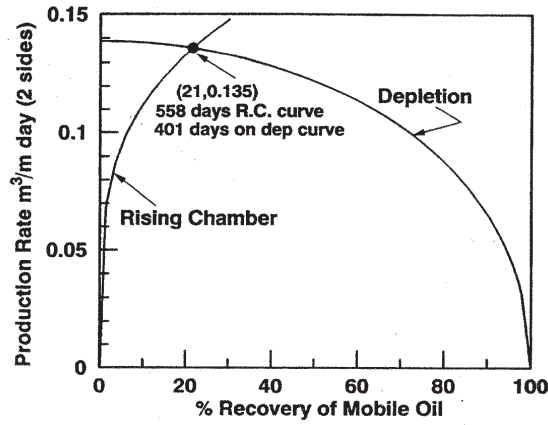


Figure D.7: Oil Production Rate Versus Recovery (Source [1])

Years	q	t^*	q^*	Recovery (above production well)
0	0			0
0.5	0.093			0.048
1.0	0.117			0.120
1.53	0.135	0.169	1.202	0.212
2.0	0.133	0.242	1.177	0.293
3.0	0.124	0.395	1.097	0.467
4.0	0.111	0.549	0.979	0.627
5.0	0.093	0.703	0.821	0.766
6.0	0.071	0.857	0.625	0.878
7.0	0.044	1.011	0.390	0.957

Table D.2: Oil Sand Recovery Percentage (Source [1])

In this final production stage, the chamber temperature and pressure slowly fall. As heat is transferred into the bitumen surrounding the chamber, some additional bitumen heating occurs, resulting in oil production. Oil production after steam injection halts is approximately 50% of previous levels, and drops rapidly [1].

D.1.3 Processing of Material Extracted by SAGD

The material that exits the bitumen production wells is a mixture of bitumen, water, sand, and light hydrocarbon gases. After it leaves the ground, the material enters a processing facility. First, the material is sent to a separation vessel that allows the hydrocarbon gases to rise to the top and the water to settle to the bottom. Although the amount of sand in the material when it leaves the ground is small, any sand that is present will also settle to the bottom of the vessel. This sand is periodically removed from the bottom of the vessel and disposed of. The light hydrocarbon gases that are separated from the bitumen can be blended with the byproduct hydrocarbon gases described in Section D.2,

and used for similar purposes. Some type of diluent will also be added to the material in the separation vessel. The diluent allows the bitumen to be more easily separated from the water, and serves other purposes as well. After the bitumen leaves the separation vessel, it is mixed with additional diluent and undergoes final treatment to remove as much of the remaining water and sand as is reasonably possible. This creates a product known as dilbit. Section D.2 will discuss the various types of diluents, other reasons why diluent is needed, and the different options for what can be done with dilbit. [15] [17]

D.2 Upgrading

D.2.1 Characteristics of Bitumen

The final product of both the surface mining and in-situ methods is a material known as diluted bitumen, or dilbit [2]. Dilbit is a mixture consisting of bitumen and diluent, which will be discussed further in Sections D.2-Blending Bitumen with Diluent and D.2-Naptha Recovery. Bitumen is a hydrocarbon material that is considered to be of low quality compared to conventional crude oil [102]. It is high in sulfur and nitrogen, and contains significant vanadium and nickel impurities [103]. Additionally, bitumen has a high carbon residue, which is the proportion of the material that cannot be distilled into other products [102][104]. This residue has a lower hydrogen-to-carbon ratio and higher molecular weight than the rest of the material [102]. Table D.3 lists some of the important characteristics of Athabasca bitumen.

	Bitumen	Synthetic Crude	Conventional Crude
API-Gravity	8	32	35
Viscosity (centistoke @ 100°F)	500,000	6	10
% Carbon by Weight	83	86	86
% Hydrogen by Weight	10.6	13	13.5
% Nitrogen by Weight	0.4	< 0.1	0.2
% Sulfur by Weight	4.8	< 0.2	0.1
ppm of Nickel	100	0	5
ppm of Vanadium	250	0	10
% Carbon Residue by Weight	14	0	5

Table D.3: Properties of Athabasca Bitumen, Synthetic Crude Oil Produced from Bitumen, and Conventional Crude Oil

D.2.2 Blending Bitumen with Diluent

The raw bitumen that is extracted, because of its high viscosity, cannot be transported in a pipeline [103]. Therefore it must be processed into a form that can be piped away. This is done by adding diluent to the bitumen during the processing of the material extracted by SAGD, as was described in Section D.1.3. One option is to blend the bitumen with a hydrocarbon condensate, made from the heaviest part of natural gas [105]. The condensate is a relatively light hydrocarbon that serves as a diluent because it dilutes the heavy bitumen with lighter material [105]. Natural gas condensate has traditionally been considered to be the best diluent for diluting bitumen for shipment off-site [106]. However, there are currently some concerns about whether the supply of this diluent will be adequate in the future [105][106]. As a result, some companies are either beginning to switch or considering a switch to alternative diluents for bitumen requiring off-site shipment, such as naphtha, conventional crude oil, or even the synthetic crude oil described in Section D.2-On-site Upgrading of Bitumen [106]. Diluents used to dilute bitumen for shipment by pipeline must be imported from off-site [105][106]. The diluent is added to the bitumen to create a mixture, known as dilbit [2], that is approximately 30% diluent and 70% bitumen [105]. The dilbit has a viscosity that is low enough so that it can be shipped by pipeline to an off-site upgrading facility [105]. It can either be sold as-is to another company that will upgrade it, or can be upgraded by the same company that extracted it.

D.2.3 On-site Upgrading of Bitumen

Another option is to perform on-site upgrading of the bitumen into a product known as synthetic crude oil, also known as syncrude [102]. This material, like dilbit, has a low enough viscosity to allow it to be piped to market [103]. Syncrude is a material that is similar to conventional crude oil, but is artificially synthesized instead of being found in nature [102]. Upgrading involves three major sub-processes: naphtha recovery, coking, and hydrotreating [102][38][107]. Figure D.8 provides a schematic of the upgrading process. The schematic also includes vacuum distillation, an optional sub-process [102][38][107].

Naphtha Recovery

Although on-site upgrading facilities eliminate the need to pipe bitumen, diluent is still required so that the bitumen will not solidify before the upgrading process [103]. A relatively lightweight hydrocarbon, known as naphtha, is added to the bitumen during

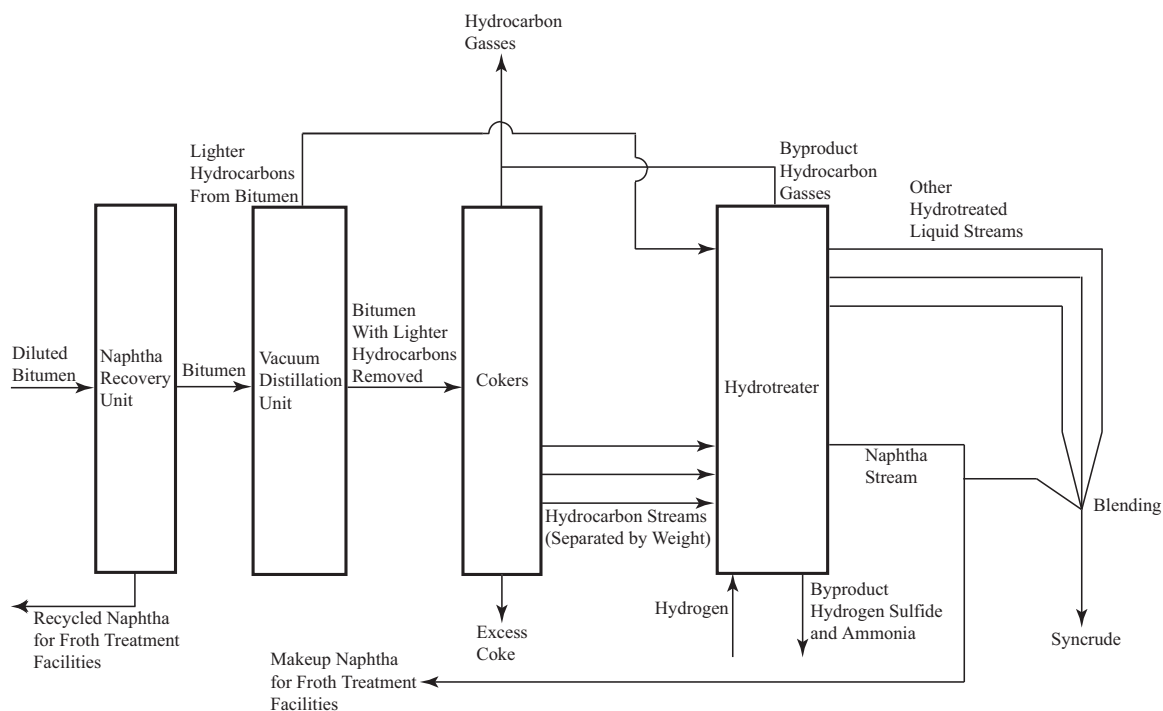


Figure D.8: Upgrading Process Schematic (Adapted from [102][38][107])

the froth treatment step of the bitumen extraction process [102][38]. The naphtha remains mixed with the bitumen until the bitumen enters the on-site upgrading plant [38]. Naphtha is a type of diluent that is considered to be a substitute for the hydrocarbon condensate diluent mentioned in Section D.2-Blending Bitumen with Diluent [2]. Once the bitumen enters this plant, the naphtha diluent is separated from the mixture. Although the diluent that is removed is recycled, there are some diluent losses because the process is not perfectly efficient [38]. These diluent losses are made up using naphtha diluent produced during the hydrotreating process described in Section D.2-Hydrotreating [38][107]. Naphtha, rather than natural gas condensate, is the diluent of choice when bitumen is upgraded on site, because additional diluent does not need to be imported from off-site.

Coking

Coking, when used for bitumen upgrading, involves transforming the bitumen into lighter hydrocarbons and coke, and removing this coke [102]. The part of the coking process which involves the transformation of heavy hydrocarbons into lighter ones via the breaking up of large hydrocarbon chains is known as cracking [108]. The coke that is produced by coking is essentially the carbon residue part of the bitumen [109]. Coking also removes much of the sulfur, nitrogen, and metal impurities from bitumen, as these tend to settle into the coke [104]. The two types of coking that are currently used for bitumen upgrading are delayed coking and fluid coking [102]. Either one can be used for a given upgrading operation [102][38][107]. The choice of coking method does not affect the quantity of

energy that needs to be supplied by the nuclear reactor, since energy for both methods can be supplied by burning the byproduct coke that is produced by the cokers [102][38][107]. The bitumen can be sent through a vacuum distillation unit, which vacuums off the lighter hydrocarbons in the bitumen, before entering the cokers. These lighter hydrocarbons are sent directly to the hydrotreater [38][107]. This reduces the amount of material that needs to be processed in the cokers, and it also prevents some of the liquid hydrocarbons from being cracked into lighter hydrocarbon gases in the coker. Producing larger quantities of liquids is beneficial because this increases the volume of liquids available to be blended into the final syncrude product [102][38][107].

Delayed Coking In delayed coking, the bitumen is most commonly preheated to approximately 480°C and then sent into one of two coking drums [102][104]. The lighter hydrocarbons (liquids and gases) are separated out of the drum, while the heavier coke stays in the drum. The drums are paired so that one of them can always be on-line while the coke is being removed from the other one. The on-line and off-line cycle for each delayed coking drum usually lasts 24 to 48 hours. The lighter hydrocarbons that were separated out of the drum are separated by weight in the fractionator, a device designed for this purpose [104]. Delayed coking, when used for bitumen upgrading, has a liquid yield of approximately 86%. Therefore 86% by volume of the bitumen processed is converted to liquid hydrocarbon products [107].

Fluid Coking In fluid coking, preheated bitumen is sent into a reactor vessel containing a 510–540°C fluidized coke bed. The bitumen is cracked into coke and lighter hydrocarbons, as in delayed coking [102][104]. In fluid coking, however, the coke that is produced attaches onto the individual particles in the fluidized coke bed, and the lighter hydrocarbons move to the top of the reactor vessel. Any remaining heavy hydrocarbons among these light hydrocarbons are sent back to the bitumen being fed into the vessel. The light hydrocarbons are sent to a fractionator that separates the light hydrocarbons by weight. The fluidized coke flows between the reactor vessel and a coke heating unit, and this transfers heat into the reactor to keep the coking process running [102]. A portion of the coke in the fluidized coke bed is continually removed from the reactor through an opening in the reactor; this eliminates the necessity to periodically open the vessels to remove coke, as is the case with delayed coking [102][104][107]. Fluid coking, when used for bitumen upgrading, has a liquid yield of approximately 88% [107].

Uses for Coking Byproducts The byproduct coke that is created by the delayed coking and fluid coking processes is burned to provide heat for the coking process [102][107]. This is very economical because it prevents the need to import other fuels for this purpose.

Unfortunately, there is not a wide market for the excess coke beyond what is used at the plant; some companies are simply storing their excess coke until they are able to find a market for it [103][107]. Any byproduct gases (very light hydrocarbons) that are created can be used in place of natural gas if there are any plant systems that still require it [38]. If there is no on-site need for these gases, they could conceivably be shipped off site for sale, or used at other bitumen upgraders which still require natural gas and could use these fuel gases as a substitute.

Hydrotreating

The hydrocarbon liquids that are produced during the coking process are then sent to the second major step in the upgrading process, hydrotreating. Hydrotreating involves exposing the liquids to high hydrogen pressures and temperatures. The hydrogen reacts with the sulfur and nitrogen remaining in the liquid feed to form hydrogen sulfide and ammonia, and it also provides hydrogen atoms to bond with empty sites on the hydrocarbon chains [102]. The liquids are separated by weight and hydrotreated as separate streams, since higher pressures and temperatures are optimal for heavier hydrocarbons, and lower pressures and temperatures are best for lighter hydrocarbons [102][38][107]. Hydrogen sulfide and ammonia will be removed from the hydrotreated products [102]. One of the hydrotreater streams treats naphtha, which after hydrotreating can be used as make-up diluent to replace that which is lost between the froth processing and diluent recovery described in Section D.1.3 [107]. Any hydrocarbons coming from the hydrotreater that are light enough to be in gaseous form can be mixed with the gases from the coker and used for the same purposes. The various liquid hydrocarbons from the hydrotreater are blended together to form the final product, synthetic crude oil [102].

D.2.4 Characteristics of Syncrude

Syncrude can be refined into petroleum products such as gasoline similarly to the way that conventional crude oil can; however, there are some differences between the two. Syncrude has a slightly lower API-gravity and slightly higher sulfur content than conventional crude does [102]. API-gravity is a convenient method, defined by the American Petroleum Institute, of expressing the specific gravity of a liquid hydrocarbon [38]. Table D.3, which describes the properties of bitumen, also compares the characteristics of syncrude and conventional crude oil. Lower API-gravity and higher sulfur content generally decrease the market value of crude oil [110]. The market price of syncrude varies with the market price of conventional crude oil (light sweet crude); the price of syncrude can be approximated to be C\$1.00 less than the price of conventional crude [111]. For

comparison purposes, dilbit has a price similar to that of Lloydminster Blend [2], which in 2004 was valued at roughly two-thirds of the price of synthetic crude [110]. Although dilbit is less valuable than syncrude, its production does not require the construction of an upgrader, leading to considerable savings in capital costs.

D.3 Hydrogen Production

The two most common methods of hydrogen production are steam methane reforming (SMR) and high temperature steam electrolysis (HTSE).

Steam Methane Reforming

SMR involves a chemical reaction between methane and high temperature steam. To begin the process, methane is combined with steam at 750–800°C producing a mixture known as syngas, composed primarily of hydrogen and carbon monoxide.

In the second step, known as the water gas shift reaction, the carbon monoxide produced in the first step is reacted with steam over a catalyst to form hydrogen and carbon dioxide. This process occurs in two stages, consisting of a high temperature shift at 350°C and a low temperature shift at 190–210°C. The empirical formula for the process is as follows:



High Temperature Steam Electrolysis

The primary advantage of HTSE over SMR is the lack of carbon emissions in the former process. Not only that, but given the assumption of this report, that the nuclear option will be employed, it is more immediately applicable to this use because of the steam production involved. Finally, HTSE is significantly more efficient than the leading high temperature thermo-chemical methods and traditional water electrolysis. In this method, steam is preheated to around 300°C, after which it is sent through recuperating heat exchangers. When it has reached 900°C, it is sent through an electrolyzer, where an electric current is sent through the gas, separating the gas into hydrogen and oxygen. This reaction is described by the following process:



When it has reached 900°C, it is sent through an electrolyzer, where an electric current

is sent through the gas, separating the gas into hydrogen and oxygen. This reaction is described by the following process:



Appendix E

Power Systems

E.1 Steam Turbines

In the case where the reactor generates electricity as well as process heat, the system must contain a turbine. This turbine is run in a secondary loop, where heat is provided with a steam generator by the reactor's primary coolant flow. The secondary loop can contain either water or helium as a heat transfer medium, and there are advantages associated with each.

E.1.1 Rankine Cycle

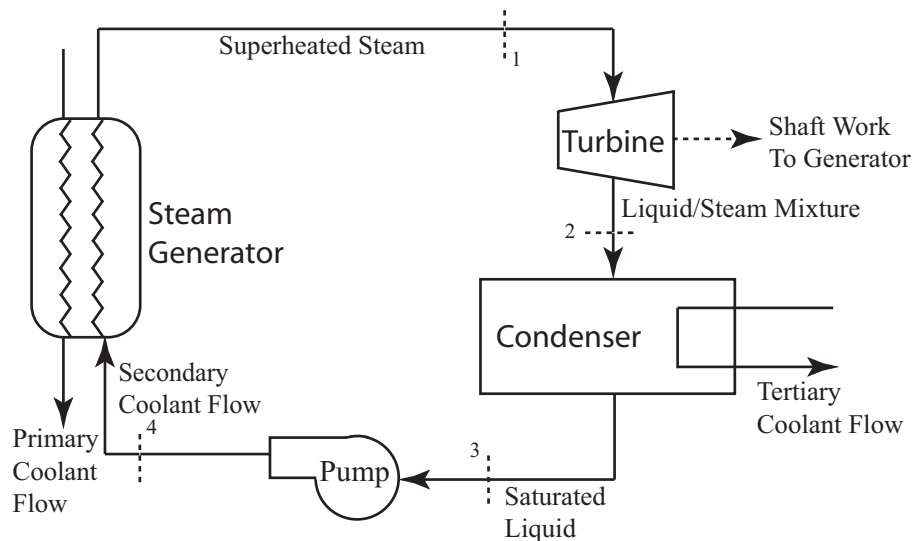


Figure E.1: Basic Rankine Cycle (Adapted from [112])

In the first case, where this secondary loop contains water, the loop will operate based on the principles of a Rankine cycle. Figure E.1 shows a diagram of the components of

a typical Rankine cycle steam plant, and Equations (E.1)–(E.8) provide a summary of the general thermodynamic equations that govern Rankine cycles. In these equations, h_n refers to the enthalpy per unit mass of the fluid at any point n in Figure E.1. W represents shaft work, Q represents heat, and m represents mass. \dot{W} , \dot{Q} , or \dot{m} indicates shaft work per unit time, heating per unit time, or mass flow per unit time, respectively. The net work ratio, or NWR , gives the ratio of shaft work to the generator to total shaft work generated by the turbines. This ratio will be less than one by definition since some of the shaft work generated must be used to provide shaft work for plant equipment such as pumps [112].

$$\text{Turbine Power:} \quad \dot{W}_{1-2} = \dot{m}(h_1 - h_2) \quad (\text{E.1})$$

$$\text{Condenser Loads:} \quad \dot{Q}_{2-3} = \dot{m}(h_3 - h_2) \quad (\text{E.2})$$

$$\text{Pump Power:} \quad \dot{W}_{3-4} = \dot{m}(h_1 - h_4) \quad (\text{E.3})$$

$$\text{Steam Generator Load:} \quad \dot{Q}_{4-1} = \dot{m}(h_1 - h_4) \quad (\text{E.4})$$

$$\text{Energy Conversion Efficiency:} \quad \eta = \frac{\dot{W}_{net}}{\dot{Q}_{steamgenerator}} = \frac{(h_1-h_2)+(h_3-h_4)}{(h_1-h_4)} \quad (\text{E.5})$$

$$\eta = 1 - \frac{(h_2-h_3)}{(h_1-h_4)} \quad (\text{E.6})$$

$$\text{Net Work Ratio:} \quad \frac{\dot{W}_{net}}{\dot{W}_{grosspositive}} = \frac{(h_1-h_2)+(h_3-h_4)}{(h_1-h_2)} \quad (\text{E.7})$$

$$NWR = 1 - \frac{(h_4-h_3)}{(h_1-h_2)} \quad (\text{E.8})$$

Heat is transferred from the primary loop to the secondary loop through a steam generator. This steam generator can be modeled as a constant pressure heat exchanger. As the secondary flow passes through this steam generator, it is converted into superheated steam. Superheating the steam rather than simply heating to the saturation point improves the overall efficiency of the Rankine cycle. The higher temperature the steam reaches, the greater the level of efficiency that can be achieved. Temperature is limited by two factors: first, superheated steam exiting the steam generator cannot exceed 560°C due to increased potential for damage to the steam generator beyond this temperature; second, the temperature of the steam cannot exceed the temperature of the primary coolant fed to the steam generator producing the steam. Producing steam of higher pressure in the steam generator also increases the Rankine cycle efficiency [112].

Upon leaving the steam generator, the superheated steam passes into the turbine. The turbine in the Rankine cycle can be modeled as an adiabatic shaft work machine [112]. The pressure decreases and the steam partially condenses as it passes through the turbine. The energy that is transferred from the steam becomes the work output for the turbine. This shaft work is used to rotate a generator, which in turn generates the final product of electricity.

The steam/water mixture then passes into a condenser, which, like the steam generator, can be modeled as a constant pressure heat exchanger. The condenser transfers enough energy from the steam/water mixture to convert the mixture back into a saturated liquid. This energy is transferred into an energy sink, such as a tertiary coolant loop or the atmosphere. The condensed secondary coolant can now be pumped back into the steam generator to begin the process again [112].

Figure E.2 shows a T-s diagram for a typical Rankine cycle with superheated steam. The T-s diagram is a plot of the relative temperature and entropy of the secondary coolant fluid at each of the locations, points 1–4 in Figure E.2. Fluids represented by points underneath the bell-shaped curve on the diagram will be liquid-steam mixtures; points outside and to the left of the curve represent liquids; and points outside and to the right of the curve represent steam. Points on the curve represent either saturated liquid or saturated steam, depending on whether they are on the left or right half of the curve, respectively.

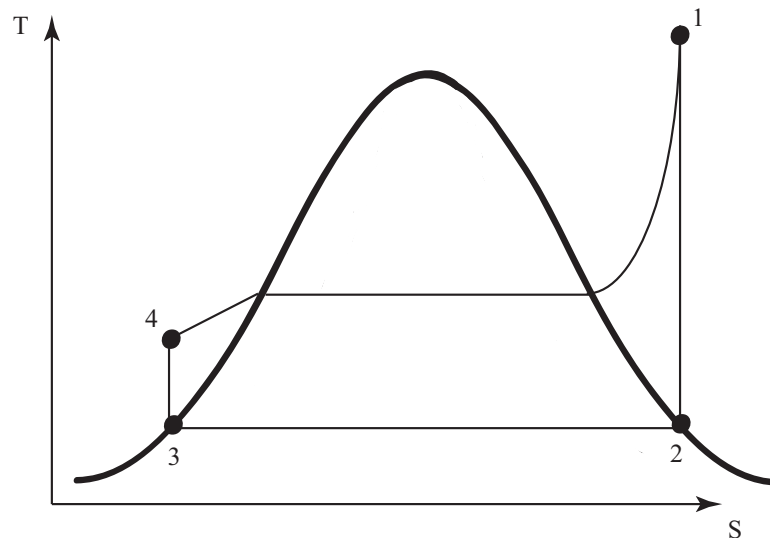


Figure E.2: Temperature-Entropy Chart for Rankine Cycle (Adapted from [112])

Although the Rankine cycle plant just described has only one turbine for simplicity, an actual plant must have two turbines, a high pressure turbine and a low pressure turbine. The superheated steam from the steam generator first enters the high pressure turbine, then it exits the turbine as a liquid/steam mixture. This mixture passes into a reheater, which reheats the mixture back to superheated steam. The heat for the reheater is provided by a stream of superheated steam from the reactor. The newly superheated steam from the reheater is sent into the low pressure turbine. The liquid/steam mixture exiting the low pressure turbine is sent to the condenser, as was the mixture exiting the single turbine in the simplified Rankine plant. In this two-turbine situation, a smaller percentage of the steam passing through the turbines is allowed to condense before leaving the turbines. This is necessary in actual Rankine plants because lower quality steam can

be damaging to turbines. Having two turbines makes it possible to achieve this while still generating the needed quantity of shaft work. In addition, the use of reheating improves the overall efficiency of the Rankine plant [112].

In actual Rankine steam plants, regenerative feed water heating is also typically used to improve overall efficiency of the plant. Regenerative heating involves preheating the secondary coolant entering the steam generator, so that the temperature differential between the primary and secondary coolant as they pass through the steam generator will not be as large. This is accomplished by diverting a portion of the liquid/steam mixture that is passing through the high and low pressure turbines out of the turbines, and sending it to one of two reheaters. The mixture from the high pressure turbine is diverted to the high pressure feedwater heater, and the mixture from the low pressure turbine is diverted to the low pressure feedwater heater. This mixture stays in the feedwater heaters until it is completely condensed, and then it is sent through steam trap valves, which only allow liquid to pass, back to the condenser [112]. Figure E.3 provides a schematic of a realistic Rankine cycle plant, including two turbines, a reheater, and feedwater heaters.

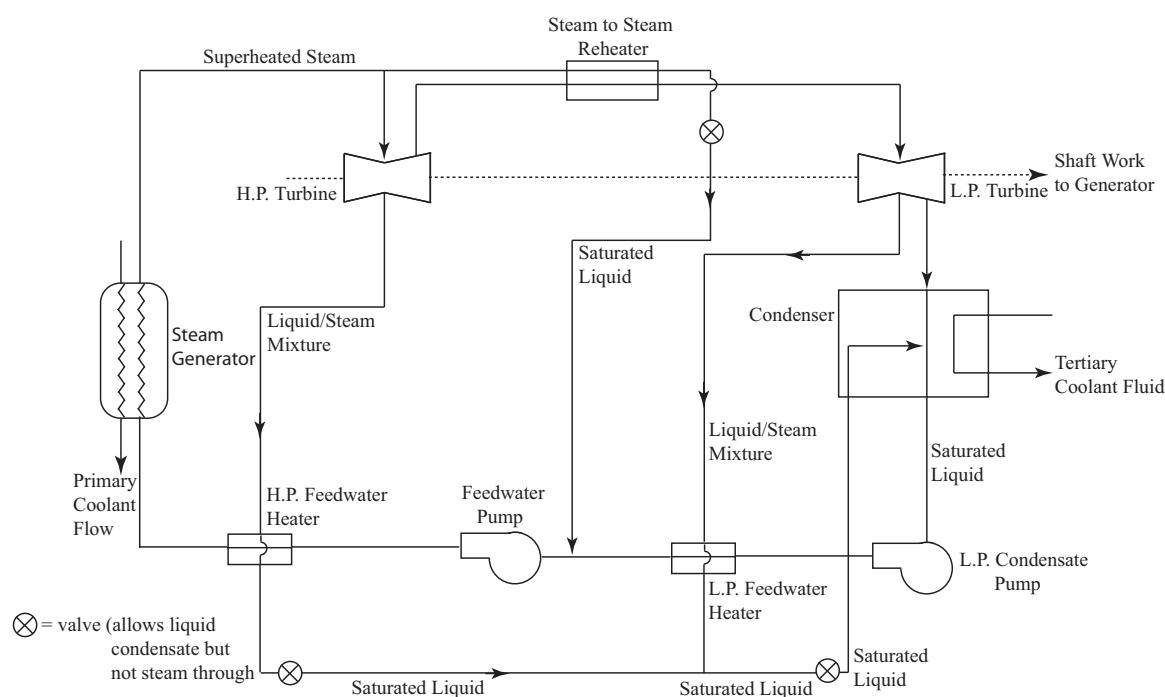


Figure E.3: Rankine cycle plant (Adapted from [112])

The secondary turbine loops of both the ACR-700 and AP600 reactors operate as Rankine cycles, since the secondary loops of these reactors run on water [40][48]. Although the secondary loops of each of these reactors have their own characteristic design, these systems operate on the same principles as the realistic Rankine cycle plant just described [40][48].

E.2 High Temperature Gas Turbines

The efficiency of high temperature reactors is largely achieved through the turbines that are used. High temperature helium turbines are able to produce efficiencies of up to 93% with current technology.

The working fluid has an important impact on the turbine. The specific heat of helium is five times the specific heat of air and steam. The greater the specific heat of the working fluid, the more turbine stages are required to achieve a particular temperature drop. Therefore, a turbine used to process helium has about five times the stages of a steam turbine.

The characteristics of helium allow for turbines with smaller rotor diameters, shorter blade lengths, and faster speeds than conventional turbines.

E.2.1 Brayton Cycle

The high efficiencies of up to 50% in the electric generation with a HTGR is possible through the utilization of a single loop, regenerative Brayton cycle. A gas turbine used in a Brayton cycle coupled with a HTGR offers efficiency gains of approximately 50% over existing steam Rankine cycles used in electric power generation with water reactors.

The theoretical Brayton cycle consists of a compressor, a turbine, and two heat transfer rates. In application, the hot, inert helium gas from the reactor, represented by point 3 in Figure E.4, first passes through the turbine.

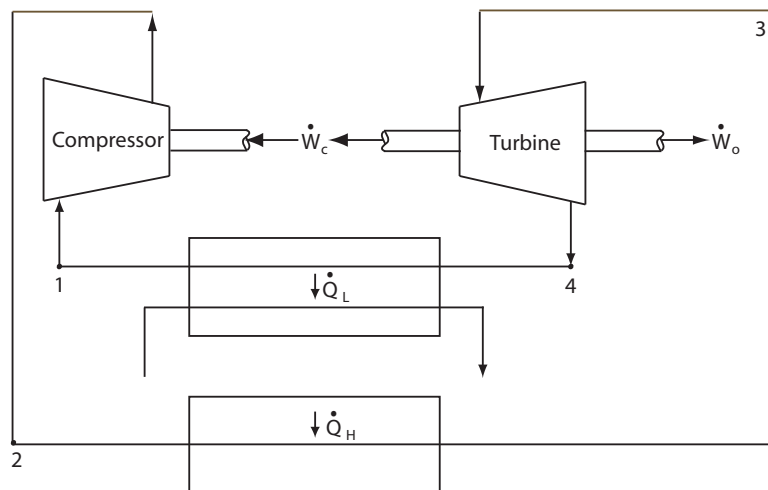


Figure E.4: Brayton Cycle

Mechanical power is produced, and a fraction of the power is used to drive a compressor. The rest of the power is output power that will ultimately drive a generator to create

electric power.

The helium stream then exits the turbine and reaches point 4, where the stream is cooled. The cooling of the stream reduces the power necessary to drive the compressor.

Efficiency of the Brayton cycle is highly dependent on the ratio of temperatures between point 3 and point 1. After high values of this ratio, higher efficiencies are possible. Unfortunately, temperatures for the inlet stream to the turbine are limited due to the damage done to turbine blades at these temperatures and flows. Current technology has enabled gas turbines to handle temperatures of up to 1,100°C, which safely places such turbine use within the range of an HTGR.

The helium stream then enters the compressor, where the pressure of the stream is increased such that it can be recycled back into the reactor. Afterwards, the temperature of the stream is raised to the original levels, such that the cycle can start again.

The efficiency equation for the Brayton cycle assumes that regeneration is used to heat a gas stream at a lower temperature section of the loop with a gas stream at a higher temperature section of the loop. Regeneration can greatly increase the efficiency of the Brayton cycle with a HTGR.

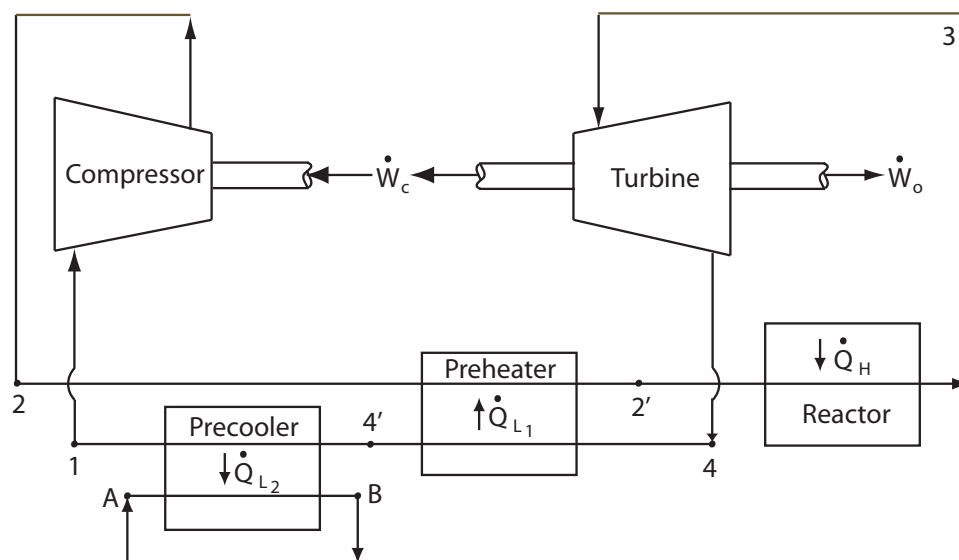


Figure E.5: Non-Intercooled Regenerative Cycle

The stream of gas that exits the turbine at point 4 passes the stream of gas leaving the compressor at point 2 in a steam generator. The higher temperature gas cools, while the lower temperature gas heats up. This effect has two advantages. The gas that increased in temperature is the feed gas into the reactor, so thus less heat input is necessary to heat the gas back up to its original temperature, the temperature at point 3. The gas that cooled down passes through the compressor, and the load on a compressor is much less when the flow-through gas is at a lower temperature. Through recuperation the rejection

heat is not lost, but rather recycled within the system.

Efficiency of the system as a function of various input and output parameters can be calculated by manipulating the original equation for efficiency. Given that the system components are not perfect and will generate entropy, the compressor will require more power and the turbine will produce less power than the ideal cases described by Equations (E.9)–(E.16).

$$\text{Compressor Power:} \quad \dot{W}_c = \dot{m}(h_1 - h_2) = \dot{m}c_P(T_1 - T_2) \quad (\text{E.9})$$

$$\text{Equivalent Heat Addition:} \quad \dot{Q}_{add} = \dot{m}(h_3 - h_2) = \dot{m}c_P(T_3 - T_2) \quad (\text{E.10})$$

$$\text{Turbine Power:} \quad \dot{W}_{turb} = \dot{m}(h_3 - h_4) = \dot{m}c_P(T_3 - T_4) \quad (\text{E.11})$$

$$\text{Equivalent Heat Rejection:} \quad \dot{Q}_{reject} = \dot{m}(h_1 - h_4) = \dot{m}c_P(T_1 - T_4) \quad (\text{E.12})$$

$$\text{Energy Conversion Efficiency:} \quad \eta = \frac{(h_1 - h_2) + (h_3 - h_4)}{(h_3 - h_2)} \quad (\text{E.13})$$

$$\eta = 1 - \frac{(h_4 - h_1)}{(h_3 - h_2)} \quad (\text{E.14})$$

$$\text{Net Work Ratio:} \quad \text{NWR} = \frac{(h_1 - h_2) + (h_3 - h_4)}{(h_3 - h_4)} \quad (\text{E.15})$$

$$\text{NWR} = 1 - \frac{(h_2 - h_1)}{(h_3 - h_4)} \quad (\text{E.16})$$

To account for the efficiency of the compressor and turbine, η_C and η_T can be added to modify the efficiency equation, which now appears as:

$$\eta = \frac{\frac{1}{\eta_C}(h_1 - h_2) + \eta_T(h_3 - h_4)}{(h_3 - h_1) - \frac{1}{\eta_C}(h_2 - h_1)} = \frac{\frac{1}{\eta_C}(T_1 - T_2) + \eta_T(T_3 - T_4)}{(T_3 - T_1) - \frac{1}{\eta_C}(T_2 - T_1)}$$

Through further manipulations, the efficiency equation can be written simply as a function of the efficiencies of the compressor and turbine, the ratio of the temperatures $\frac{T_3}{T_1}$, and the isentropic temperature ratio, $\tau = \frac{T_2}{T_1} = \frac{T_3}{T_4} = \left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} = \left(\frac{P_3}{P_4}\right)^{\frac{\gamma-1}{\gamma}}$.

$$\eta = \frac{\frac{1}{\eta_C}(T_1 - T_2) + \eta_T(T_3 - T_4)}{(T_3 - T_1) - \frac{1}{\eta_C}(T_2 - T_1)}$$

$$\eta = \frac{\frac{1}{\eta_C}(1 - \tau) + \frac{T_3}{T_1}\eta_T(1 - \tau)}{\left(\frac{T_3}{T_1} - 1\right) - \frac{1}{\eta_C}(\tau - 1)}$$

Another valuable parameter used to describe the system is the net work transfer rate, which can be described as a dimensionless variable if divided by the work transfer rate at point 1 of the cycle. A similar manipulation to the one used for efficiency can be used for the net work transfer rate ratio in order to yield a dimensionless variable that

is a function of only the system efficiencies, $\frac{T_3}{T_1}$, and the isentropic temperature ratio, $\tau = \frac{T_2}{T_1} = \frac{T_3}{T_4}$.

$$\frac{\dot{W}_{net}}{\dot{m}c_P T_1} = \frac{\frac{1}{\eta_C}(T_1 - T_2) + \eta_T(T_3 - T_4)}{T_1}$$

$$\frac{\dot{W}_{net}}{\dot{m}c_P T_1} = \frac{1}{\eta_C}(1 - \tau) + \eta_T\left(\frac{T_3}{T_1}\right)(1 - \tau)$$

The dimensionless variables for the efficiency and the work transfer rate may seem complicated, as they are the function of many different variables. However, current technology sets most of the variables, and thus the efficiencies are known. The temperatures are set by reactor design parameters.

State of the art compressors and turbines now available have efficiencies of 89% and 93%, respectively. These values are not expected to increase more than a percentage point or two in the near future, and can be considered accurate parameters of efficiency and net work ratio for the next few decades.

In a typical PBMR, the output temperature and inlet temperatures are 900°C and 480°C, respectively. Thus the value of τ is set at 0.642.

From a practical standpoint, it is necessary to estimate the number of compressors and turbines needed to handle the load of the processing plant and other demands. Turbo-compressors today can handle loads of up to 285 MWe, which corresponds to 306.5 MWth [101]. Given a 2,800 MWth load, ten turbocompressors would be necessary.

E.2.2 Combined Cycle

The use of a combined cycle in application with a PBMR has the possibility of offering improved efficiencies. Using a bottoming cycle seems to be a promising idea, however, this concept is also flawed. All the flow in the cycle prior to reaching the temperature of 100°C at point 1 in Figure E.4 is passed through the turbine, or used to recycle heat through the pre-heater, which is a highly efficient process. Sending the flow through the turbine and the heat exchanger are absolutely necessary, so diverting the stream will yield no benefit.

The main solution left is to use a split loop system, as shown in Figure 5.4(b). The heat from the reactor is diverted into two streams. One stream is used for process heat, while the other stream is used for the Brayton cycle. As earlier, one can calculate the mass flows necessary for these processes. For simplicity, the mass flows will be calculated for

multiple reactors, and then the number of reactors necessary will be determined from the necessary flows.

A possible cycle configuration is to direct the loop used for the process heat and transfer heat through a counterflow heat exchanger until the flow reaches the temperature of the steady state return feed of the process steam. Afterwards, the helium is at a temperature of 170°C and a pressure of 7 MPa, so it can be recombined with the return stream into the reactor. The configuration is depicted in Figure E.6.

Figure E.6: Combined Brayton Cycle

The return stream in a typical PBMR Brayton cycle is typically 100°C prior to preheating. Thus the return stream, prior to preheating, is now at a temperature between 100 and 170°C. The higher temperature may be able to reduce the reheating demands of the Brayton cycle, and on face-value, seems promising.

Mass flow necessary for the required electric generation can be written as a function of the temperature at point 4. The higher the temperature at point 4, the less thermal power the turbines draw from the flow. Since the turbines draw less thermal power, there is less conversion to electrical power. However, there is a desire to use a higher temperature, as less resulting flow is then necessary to transfer the requisite energy into the reheat stream between points 4 and 4'.

There is an additional constraint on the loop. Due to the heat transfer properties of the heat exchanger, the temperature at point 4' must exceed, or in an optimized state equal 2'. The temperature at point 2' is found by combining a ratio of flows. The temperature at point 4' is a function of the flows also. Since the only variable in the flows exists in the flow for the electric generation, and the variable in the flow for electric generation is the temperature at point 4, the entire system can be represented as a function of the temperature at point 4.

Three different equations must be solved in order to find the flow rates necessary for the system.

$$\dot{m}_2 = \frac{E_h}{\eta_{xh} c_{P,He} (T_3 - T_{ss})} \quad (E.17)$$

$$\dot{m}_1 = \frac{E_e}{c_{P,He} (\eta_T (T_3 - T_4) + \frac{1}{\eta_c} (T_1 - T_{1'} + T_{1''} - T_2))} \quad (E.18)$$

$$\dot{m}_1 = \frac{E_e}{c_{P,He} (\eta_T (T_3 - T_4) + \frac{1}{\eta_c} (T_1 - T_{1'} + T_{1''} - T_2))} \quad (E.19)$$

The equations are solved for with the following temperature points set.

Point	Temperature(°C)
T ₁	33
T' ₁	130
T'' ₁	33
T ₂	100
T'' ₂	500
T ₃	900

Table E.1: PBMR Brayton Cycle Temperatures

Finally, the temperatures at the points $T_{2'}$ and $T_{4'}$ can be solved for in terms of flows and temperatures at other points.

$$T_{2'} = \frac{E_h}{E_h + E_e} \times 100 + \frac{E_e}{E_h + E_e} \times 170 \quad (\text{E.20})$$

$$T_{4'} = T_4 - \frac{E_h + E_e}{T_{2''} - T_{2'}} \times E_e \quad (\text{E.21})$$

When these equations are solved, the flows are represented as functions of T_4 . Figure E.7 shows the minimum flow rate necessary for the power demands and the minimum flow rate necessary for the preheating of the system.

The temperature constraint between the temperatures is depicted in Figure E.8. Only the temperatures for which the temperature at point 4' higher than the temperature at point 2' are shown.

The flow \dot{m}_1 is finally the higher value of the flow necessary for the required electric power and the flow necessary to reheat \dot{m}_2 . Figure E.9 shows the relationship between the flows necessary for power generation and regeneration as a function of the temperature at point 4. In our application, the mass flow necessary for electric power generation dwarfs the mass flow for the regeneration. Thus the mass flow for the electric power generation is the limiting factor, and it is \dot{m}_1 . The minimum value of this mass flow as a function of temperature at point 4 is the optimal mass flow for the cycle configuration. Using the proposed configuration, 1,711 kg/sec is necessary.

Figure E.10 shows the sum of the flow needed for process heat and the flow necessary for electric power. The sum can be related to a number of PBMRs based on the typical flow of a PBMR, which is 176 kg/sec for a 400 MWth PBMR.

The results of the calculations show that the addition of the bottoming cycle has a negative effect overall effect on the efficiency of the cycle. However, there is a positive

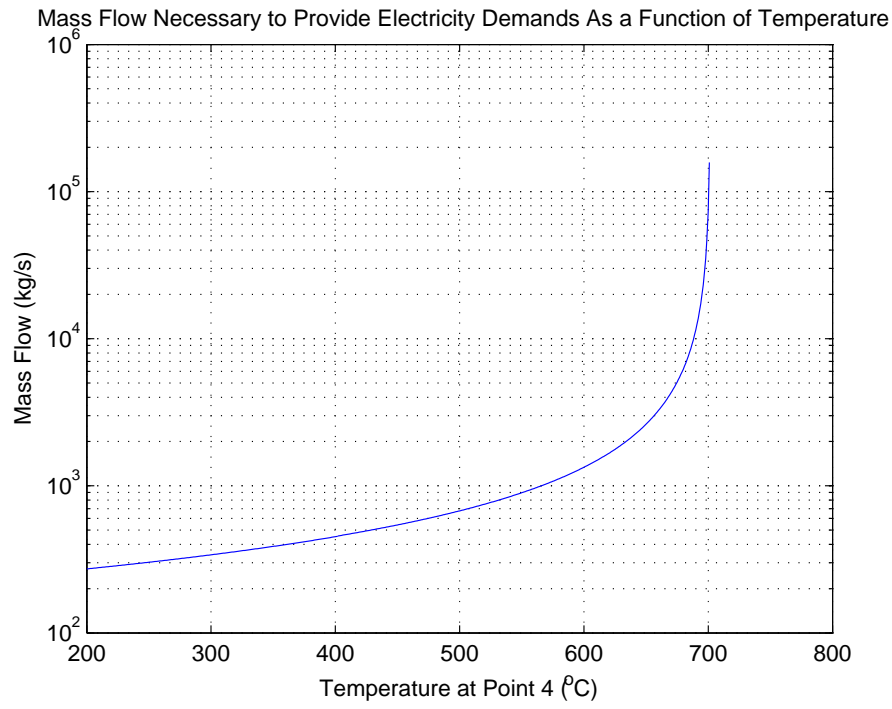


Figure E.7: Mass Flow for Electricity

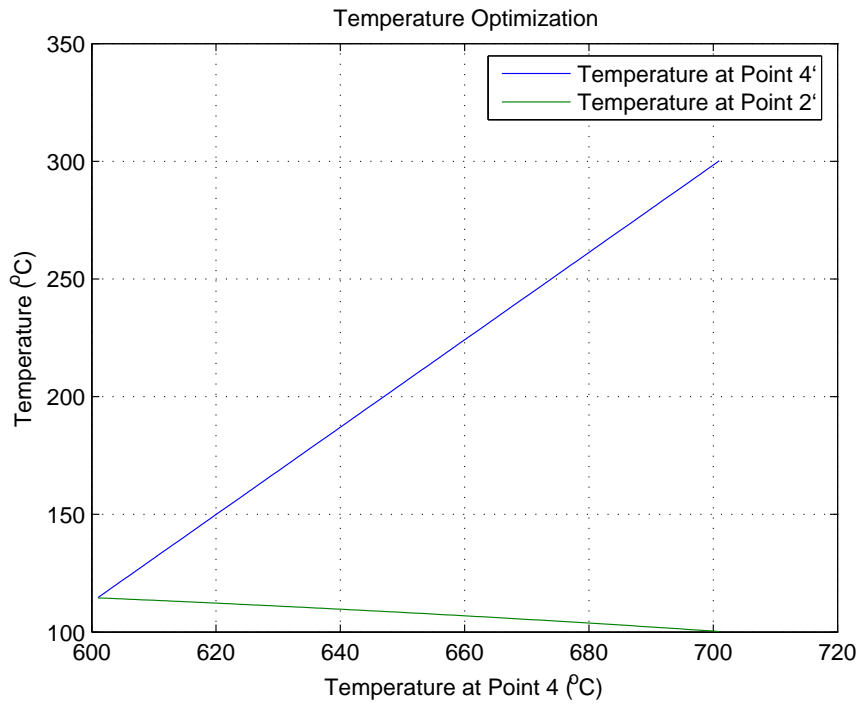


Figure E.8: Temperature Constraint

improvement in the electric efficiency of the cycle. Since 677.4 kg/sec of mass flow are required to satisfy the electric demands in this configuration, an equivalent thermal power that can be satisfied by this flow is calculated in Equation E.22

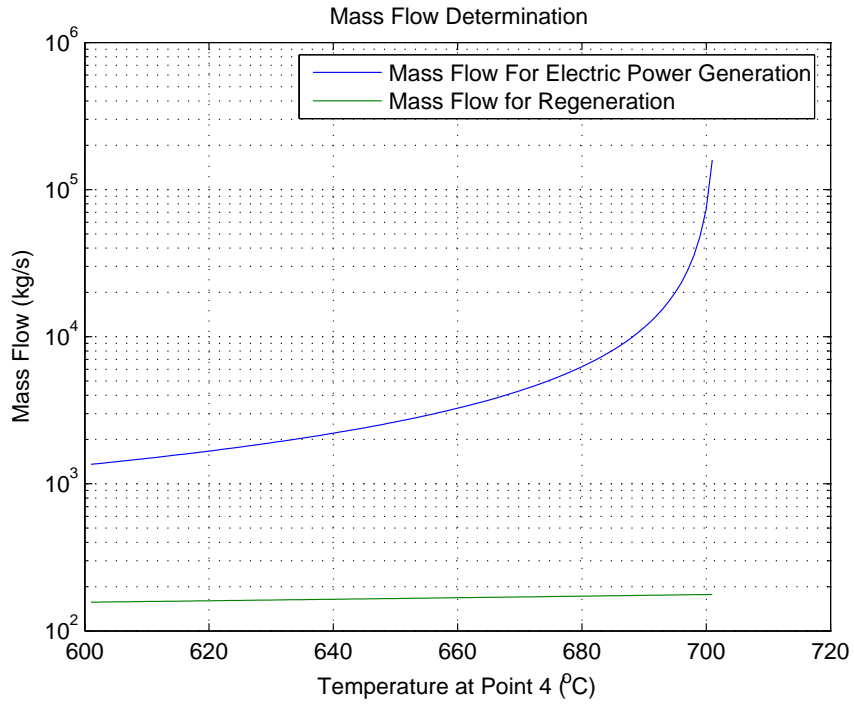


Figure E.9: Limiting Mass Flow Determination

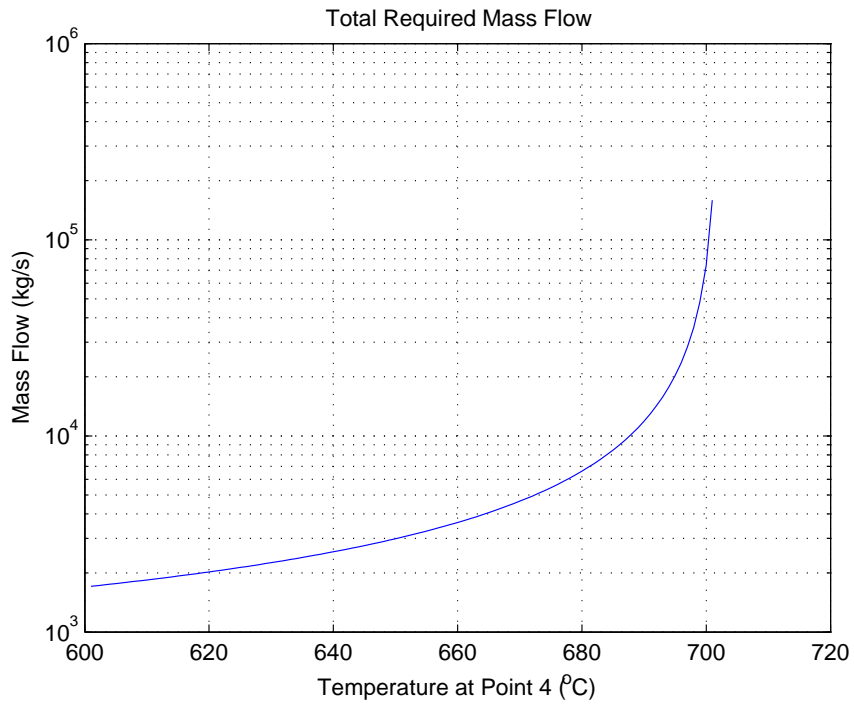


Figure E.10: Required Mass Flow

$$\left(677.4 \frac{\text{kg}}{\text{sec}}\right) \left(\frac{400 \text{MWth}}{176 \frac{\text{kg}}{\text{sec}}}\right) = 1,540 \text{MWth} \quad (\text{E.22})$$

To calculate the electric efficiency, we divide the electricity produced by the thermal

input necessary to produce the electricity. The electricity produced was 660MWe, and the thermal power necessary, as found in Equation E.22 was 1,540MWth.

$$\frac{660\text{MWe}}{1540\text{MWth}} = 43\% \quad (\text{E.23})$$

Thus the electric efficiency is about 43%, which exceeds the efficiency for electricity in a typical Brayton cycle. Unfortunately, due to the intimate way in which the electric and steam cycles are interlinked, the efficiency of the steam cycle is reduced in order to improve the electric efficiency.

The combined efficiency is simply the sum of the electric and thermal power produced divided by the total power input. The calculation of the efficiency for the combined cycle in Equation E.24 yields a lower efficiency than the separated cycles shown in Equation E.25.

$$\frac{1324\text{MW} + 660\text{MW}}{1711 \frac{\text{kg}}{\text{s}} \times \frac{400\text{MW}}{176 \frac{\text{kg}}{\text{s}}}} = 49\% \quad (\text{E.24})$$

$$\frac{1324\text{MW} + 660\text{MW}}{\frac{660}{.41}\text{MW} + 1324\text{MW}} = 64\% \quad (\text{E.25})$$

Although combined cycles seem promising, further improvements must be made off combined cycles in order to provide efficiencies that would make them desirable.

MATLAB CODE

```

T_1=33; T_1prime=130; T_1doubleprime=33; T_2=100;
T_2doubleprime=500; T_3=900;
%T_4prime=[100:1:170];
%T_2prime=T_4prime;
T_4=[200:900]; eta_t=.93; eta_c=.89; E_needed=660e6;
process_heat=1264e6+80e6;
% E_needed=250e6;
% process_heat=1264e6;

c_p=5190;
% xh_efficiency=.95;
xh_efficiency=1; T_ss=170;
mass_flow=process_heat/xh_efficiency/c_p./(T_3-T_ss);
minimum_power=E_needed/c_p./(eta_t.*(T_3-T_4)...
    +1/eta_c*(T_1-T_1prime+T_1doubleprime-T_2));

for i=1:length(minimum_power)
    if minimum_power(length(T_4)+1-i)<0
        minimum_power(length(T_4)+1-i)=[];
    end
end
T_4(length(minimum_power)+1:length(T_4))=[]; figure(1)
semilogy(T_4,minimum_power) xlabel('Temperature at Point 4 (^oC)')
ylabel('Mass Flow (kg/s)') title('Mass Flow Necessary to Provide
Electricity Demands As a Function of Temperature') grid on
T_2prime=minimum_power./(mass_flow+minimum_power)*100...
    +mass_flow./(mass_flow+minimum_power)*170;
T_4prime=-((mass_flow+minimum_power).*(...
    (T_2doubleprime-T_2prime)./minimum_power-T_4);

length_T_4prime=length(T_4prime); for i=1:length(T_4prime)
    if T_4prime(length_T_4prime+1-i)<T_2prime(length_T_4prime+1-i)
        T_4prime(length_T_4prime+1-i)=[];
        T_2prime(length_T_4prime+1-i)=[];
    end
end
T_4(1:length(T_4)-length(T_4prime))=[]; figure(2)
plot(T_4,T_4prime,T_4,T_2prime) ylabel('Temperature (^oC)')
xlabel('Temperature at Point 4 (^oC)') title('Temperature

```

```

Optimization') legend('Temperature at Point 4'', 'Temperature at
Point 2'') grid on
minimum_power(1:length(minimum_power)-length(T_4prime))=[];
minimum_flow=mass_flow*(T_2doubleprime-T_2prime)./...
    (T_4-T_4prime+T_2doubleprime-T_2prime);
figure(3) semilogy(T_4,minimum_power,T_4,minimum_flow); grid on
ylabel('Mass Flow (kg/s)') xlabel('Temperature at Point 4 (^oC)')
title('Mass Flow Determination') legend('Mass Flow For Electric
Power Generation', 'Mass Flow for Regeneration') figure(4)
semilogy(T_4,minimum_power+mass_flow); ylabel('Mass Flow (kg/s)')
xlabel('Temperature at Point 4 (^oC)') title('Total Required Mass
Flow') grid on minimum_power(1)+mass_flow
new_mass_flow=(process_heat-xh_efficiency*c_p*(T_1prime-T_1+...
    T_2-T_1doubleprime)*minimum_power(1))/xh_efficiency/c_p./(T_3-T_ss)

```


Appendix F

Potential Plant Capacities

Production (bbl/day)	Process Heat (MWth)	Reactors Needed
30,000	379	1
35,000	442	1
40,000	506	1
45,000	569	1
50,000	632	1
55,000	695	1
60,000	758	1
65,000	822	1
70,000	885	1
75,000	948	1
80,000	1,011	1
85,000	1,074	1
90,000	1,138	1
95,000	1,201	1
100,000	1,264	1
105,000	1,327	1
110,000	1,390	1
115,000	1,454	1
120,000	1,517	1
125,000	1,580	1
130,000	1,643	1
135,000	1,706	1
140,000	1,770	1
145,000	1,833	1
150,000	1,896	1
155,000	1,959	1
160,000	2,022	1
165,000	2,086	2
170,000	2,149	2
175,000	2,212	2
180,000	2,275	2
185,000	2,338	2
190,000	2,402	2
195,000	2,465	2
200,000	2,528	2

Table F.1: Reactor Requirements on a bbl/day basis for ACR - Process Heat

Production (bbl/day)	Process Heat (MWth)	Electricity (MWe)	Electricity Eq (MWth)	Reactors Needed	Dedicated Reactors
30,000	403	423	1,223	1	2
35,000	470	443	1,282	1	2
40,000	537	463	1,341	1	2
45,000	604	484	1,400	1	2
50,000	672	504	1,459	2	2
55,000	739	525	1,518	2	2
60,000	806	545	1,577	2	2
65,000	873	565	1,636	2	2
70,000	940	586	1,695	2	2
75,000	1,007	606	1,754	2	2
80,000	1,075	627	1,813	2	2
85,000	1,142	647	1,872	2	2
90,000	1,209	668	1,931	2	2
95,000	1,276	688	1,990	2	2
100,000	1,343	708	2,050	2	3
105,000	1,410	729	2,109	2	3
110,000	1,478	749	2,168	2	3
115,000	1,545	770	2,227	2	3
120,000	1,612	790	2,286	2	3
125,000	1,679	810	2,345	2	3
130,000	1,746	831	2,404	3	3
135,000	1,813	851	2,463	3	3
140,000	1,881	872	2,522	3	3
145,000	1,948	892	2,581	3	3
150,000	2,015	913	2,640	3	3
155,000	2,082	933	2,699	3	4
160,000	2,149	953	2,758	3	4
165,000	2,216	974	2,818	3	4
170,000	2,284	994	2,877	3	4
175,000	2,351	1,015	2,936	3	4
180,000	2,418	1,035	2,995	3	4
185,000	2,485	1,055	3,054	3	4
190,000	2,552	1,076	3,113	3	4
195,000	2,619	1,096	3,172	3	4
200,000	2,686	1,117	3,231	3	4

Table F.2: Reactor Requirements on a bbl/day basis for ACR - Hydrogen

Production (bbl/day)	Process Heat (MWth)	Reactors Needed
30,000	379	1
35,000	442	1
40,000	506	1
45,000	569	1
50,000	632	1
55,000	695	1
60,000	758	1
65,000	822	1
70,000	885	1
75,000	948	1
80,000	1,011	1
85,000	1,074	1
90,000	1,138	1
95,000	1,201	1
100,000	1,264	1
105,000	1,327	1
110,000	1,390	1
115,000	1,454	1
120,000	1,517	1
125,000	1,580	1
130,000	1,643	1
135,000	1,706	1
140,000	1,770	1
145,000	1,833	1
150,000	1,896	1
155,000	1,959	2
160,000	2,022	2
165,000	2,086	2
170,000	2,149	2
175,000	2,212	2
180,000	2,275	2
185,000	2,338	2
190,000	2,402	2
195,000	2,465	2
200,000	2,528	2

Table F.3: Reactor Requirements on a bbl/day basis for AP - Process Heat

Production (bbl/day)	Process Heat (MWth)	Electricity (MWe)	Electricity Eq (MWth)	Reactors Needed	Dedicated Reactors
30,000	379	250	723	1	2
35,000	442	250	723	1	2
40,000	506	250	723	1	2
45,000	569	250	723	1	2
50,000	632	250	723	1	2
55,000	695	250	723	1	2
60,000	758	250	723	1	2
65,000	822	250	723	1	2
70,000	885	250	723	1	2
75,000	948	250	723	1	2
80,000	1,011	250	723	1	2
85,000	1,074	250	723	1	2
90,000	1,138	250	723	1	2
95,000	1,201	250	723	1	2
100,000	1,264	250	723	2	2
105,000	1,327	250	723	2	2
110,000	1,390	250	723	2	2
115,000	1,454	250	723	2	2
120,000	1,517	250	723	2	2
125,000	1,580	250	723	2	2
130,000	1,643	250	723	2	2
135,000	1,706	250	723	2	2
140,000	1,770	250	723	2	2
145,000	1,833	250	723	2	2
150,000	1,896	250	723	2	2
155,000	1,959	250	723	2	3
160,000	2,022	250	723	2	3
165,000	2,086	250	723	2	3
170,000	2,149	250	723	2	3
175,000	2,212	250	723	2	3
180,000	2,275	250	723	2	3
185,000	2,338	250	723	2	3
190,000	2,402	250	723	2	3
195,000	2,465	250	723	2	3
200,000	2,528	250	723	2	3

Table F.4: Reactor Requirements on a bbl/day basis for AP - Electricity

Production (bbl/day)	Process Heat (MWth)	Electricity (MWe)	Electricity Eq (MWth)	Reactors Needed	Dedicated Reactors
30,000	403	423	1,223	1	2
35,000	470	443	1,282	1	2
40,000	537	463	1,341	1	2
45,000	604	484	1,400	2	2
50,000	672	504	1,459	2	2
55,000	739	525	1,518	2	2
60,000	806	545	1,577	2	2
65,000	873	565	1,636	2	2
70,000	940	586	1,695	2	2
75,000	1,007	606	1,754	2	2
80,000	1,075	627	1,813	2	2
85,000	1,142	647	1,872	2	2
90,000	1,209	668	1,931	2	2
95,000	1,276	688	1,990	2	3
100,000	1,343	708	2,050	2	3
105,000	1,410	729	2,109	2	3
110,000	1,478	749	2,168	2	3
115,000	1,545	770	2,227	2	3
120,000	1,612	790	2,286	3	3
125,000	1,679	810	2,345	3	3
130,000	1,746	831	2,404	3	3
135,000	1,813	851	2,463	3	3
140,000	1,881	872	2,522	3	3
145,000	1,948	892	2,581	3	4
150,000	2,015	913	2,640	3	4
155,000	2,082	933	2,699	3	4
160,000	2,149	953	2,758	3	4
165,000	2,216	974	2,818	3	4
170,000	2,284	994	2,877	3	4
175,000	2,351	1,015	2,936	3	4
180,000	2,418	1,035	2,995	3	4
185,000	2,485	1,055	3,054	3	4
190,000	2,552	1,076	3,113	3	4
195,000	2,619	1,096	3,172	3	4
200,000	2,686	1,117	3,231	4	4

Table F.5: Reactor Requirements on a bbl/day basis for AP - Hydrogen

Production (bbl/day)	Process Heat (MWth)	Reactors Needed
30,000	379	1
35,000	442	2
40,000	506	2
45,000	569	2
50,000	632	2
55,000	695	2
60,000	758	2
65,000	822	3
70,000	885	3
75,000	948	3
80,000	1,011	3
85,000	1,074	3
90,000	1,138	3
95,000	1,201	4
100,000	1,264	4
105,000	1,327	4
110,000	1,390	4
115,000	1,454	4
120,000	1,517	4
125,000	1,580	5
130,000	1,643	5
135,000	1,706	5
140,000	1,770	5
145,000	1,833	5
150,000	1,896	5
155,000	1,959	5
160,000	2,022	6
165,000	2,086	6
170,000	2,149	6
175,000	2,212	6
180,000	2,275	6
185,000	2,338	6
190,000	2,402	7
195,000	2,465	7
200,000	2,528	7

Table F.6: Reactor Requirements on a bbl/day basis for PBMR - Process Heat

Production (bbl/day)	Process Heat (MWth)	Electricity (MWe)	Electricity Eq (MWth)	Reactors Needed	Dedicated Reactors
30,000	379	250	610	3	3
35,000	442	250	610	3	4
40,000	506	250	610	3	4
45,000	569	250	610	3	4
50,000	632	250	610	4	4
55,000	695	250	610	4	4
60,000	758	250	610	4	4
65,000	822	250	610	4	5
70,000	885	250	610	4	5
75,000	948	250	610	4	5
80,000	1,011	250	610	5	5
85,000	1,074	250	610	5	5
90,000	1,138	250	610	5	5
95,000	1,201	250	610	5	6
100,000	1,264	250	610	5	6
105,000	1,327	250	610	5	6
110,000	1,390	250	610	6	6
115,000	1,454	250	610	6	6
120,000	1,517	250	610	6	6
125,000	1,580	250	610	6	7
130,000	1,643	250	610	6	7
135,000	1,706	250	610	6	7
140,000	1,770	250	610	7	7
145,000	1,833	250	610	7	7
150,000	1,896	250	610	7	7
155,000	1,959	250	610	7	7
160,000	2,022	250	610	7	8
165,000	2,086	250	610	7	8
170,000	2,149	250	610	7	8
175,000	2,212	250	610	8	8
180,000	2,275	250	610	8	8
185,000	2,338	250	610	8	8
190,000	2,402	250	610	8	9
195,000	2,465	250	610	8	9
200,000	2,528	250	610	8	9

Table F.7: Reactor Requirements on a bbl/day basis for PBMR - Electricity

Production (bbl/day)	Process Heat (MWth)	Electricity (MWe)	Electricity Eq (MWth)	Reactors Needed	Dedicated Reactors
30,000	403	423	1,030	4	5
35,000	470	443	1,080	4	5
40,000	537	463	1,130	5	5
45,000	604	484	1,180	5	5
50,000	672	504	1,230	5	6
55,000	739	525	1,279	6	6
60,000	806	545	1,329	6	7
65,000	873	565	1,379	6	7
70,000	940	586	1,429	7	7
75,000	1,007	606	1,479	7	7
80,000	1,075	627	1,528	7	7
85,000	1,142	647	1,578	7	7
90,000	1,209	668	1,628	8	9
95,000	1,276	688	1,678	8	9
100,000	1,343	708	1,728	8	9
105,000	1,410	729	1,777	9	9
110,000	1,478	749	1,827	9	9
115,000	1,545	770	1,877	9	9
120,000	1,612	790	1,927	9	10
125,000	1,679	810	1,977	10	11
130,000	1,746	831	2,026	10	11
135,000	1,813	851	2,076	10	11
140,000	1,881	872	2,126	11	11
145,000	1,948	892	2,176	11	11
150,000	2,015	913	2,226	11	12
155,000	2,082	933	2,275	12	12
160,000	2,149	953	2,325	12	12
165,000	2,216	974	2,375	12	13
170,000	2,284	994	2,425	12	13
175,000	2,351	1,015	2,475	13	13
180,000	2,418	1,035	2,524	13	14
185,000	2,485	1,055	2,574	13	14
190,000	2,552	1,076	2,624	14	14
195,000	2,619	1,096	2,674	14	14
200,000	2,686	1,117	2,724	14	14

Table F.8: Reactor Requirements on a bbl/day basis for PBMR - Hydrogen

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