SNC·LAVALIN Nuclear

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NUCLEAR ENERGY OPTIONS EVALUATION REPORT

Project
Oil Sands Phase 1 Energy Options Feasibility Study

Retain Until: 2016

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Acronyms

The following acronyms and short forms are used in this document.

Ref	Item	Acronym	Description
1	Nuclear Power Plant Vendors	AECL	Atomic Energy of Canada Ltd.
2		AREVA	AREVA Inc.
3		GA	General Atomics Inc.
4		GE	General Electric Inc.
5		PBMR	Pebble Bed Modular Reactor Inc.
6	Nuclear Reactor Technologies	CANDU	CANadian Deuterium Uranium
7		BWR	Boiling Water Reactor
8		LWR	Advanced Light Water Reactor (PWR and BWR)
9		PWR	Pressurized Water Reactor
10		HTGR	High Temperature Gas Reactor
11		SGHWR	Steam Generating Heavy Water Reactor
12	Organizations	AESO	Alberta Electric System Operator
13		AECB	Atomic Energy Control Board
14		B&W	Babcock and Wilcox Inc.
15		CE	Combustion Engineering Inc. (now part of Westinghouse)
16		CNSC	Canadian Nuclear Safety Commission
17		FERC	Federal Energy Regulatory Commission (US)
18		GNEP	Global Nuclear Energy Partnership
19		IAEA	International Atomic Energy Organization
20		INET	Institute for Nuclear & New Energy Technology (China)
21		KAERI	Korean Atomic Energy Research Institute
22		MHI	Mitsubishi Heavy Industries
23		NEA	Nuclear Energy Association
24		NEI	Nuclear Energy Institute
25		NRC	Nuclear Regulatory Commission (USA)
26		OECD	Organization for Economic Development
27		OPG	Ontario Power Generation
28		ORNL	Oak Ridge National Laboratories (USA)
29		PTAC	Petroleum Technology Alliance Canada
30		SLN	SNC-Lavalin Nuclear Inc.
31	Provinces	AB	Alberta
32		BC	British Columbia
33		ON	Ontario
34	Nuclear Power Plant Designations	ACR-1000	Advanced CANDU Reactor 1000 (1000 indicates 1000 MWe Class)
35		ABWR	Advanced Boiling Water Reactor
36		AGR	Advanced Gas Cooled Reactor (reactor technology utilized in GB)
37		AP1000	Advanced Passive 1000 (1000 indicates 1000 MWe Class)
38		APWR	Advanced Pressurized Water Reactor

Ref	Item	Acronym	Description
39		CANDU 6E	CANadian Deuterium Uranium 6 Enhanced (6 indicates 600 MWe Class)
40		EPR	Evolutionary Pressurized Reactor
41		ESBWR	Enhanced Simplified Boiling Water Reactor
42		GA-HTGR	General Atomics – High Temperature Gas Reactor
43		LMFBR	Liquid Metal Fast Breeder Reactor
44		MAGNOX	Magnesium Oxide (reactor technology utilized in GB)
45		MOTHER	Modular Thermal Helium Reactor
46		PBMR	Pebble Bed Modular Reactor
47		SMART	System-integrated Modular Advanced Reactor
48		THTR-300	Thorium High Temperature Reactor (300 MW Class built in Germany)
49		US-APWR	United States Advanced Pressurized Water Reactor
50	Units of Measure	b/d	Barrels per day
51		kg	Kilogram
52		kPa	Kilo Pascal
53		m/kWh	mills per kilowatt hour
54		M	Million
55		Mg	Milligram
56		MPa	Mega Pascal
57		MW	Megawatt
58		MWe	Megawatt Electrical
59		MWth	Megawatt thermal
60		SCF	Standard cubic Feet
61	General	C&I	Control and Instrumentation
62		CCW	Condenser Cooling Water
63		COL	Combined Operating Licence
64		D_2O	Deuterium Oxide (heavy water)
65		DCL	Direct Coal Liquification
66		EA	Environmental Assessment
67		EDI	Electrodeionization
68		FOAK	First-Of-A-Kind
69		GHG	Green House Gas
70		gpm	Gallons Per Minute
71		H_20	Water (light/ordinary water)
72		HLS	Hot Lime Softening
73		HTC	Heat Transfer Coefficient
74		ICL	Indirect Coal Liquification
75		LWR	Light Water Reactor
76		LOCA	Loss of Coolant Accident
77		NPP	Nuclear Power Plant
78		NSP	Nuclear Steam Plant
79		NSSS	Nuclear Steam Supply System
80		OTSG	Once Through Steam Generator
81		PAH	Polycyclic Aromatic Hydrocarbons
82		R&D	Research And Development

Ref	Item	Acronym	Description
83		RFP	Request for Proposal
84		RIP	Reactor Internal Pumps
85		rpm	revolutions per minute
86		SAGD	Steam Assisted Gravity Drainage
87		SWU	Separative Work Unit
88		SG	Steam Generator
89		SOR	Steam Oil Ratio
90		SNG	Synthetic Natural Gas
91		SOR	Steam Oil Ratio
92		SPL	Standard Product Licence
93		TDS	Total Disolved Solids
94		VOC	Volatile Organic Compounds
95		WAC	Weak Acid Cation

Executive Summary

SNC-Lavalin Nuclear Inc. (SLN), under contract with PTAC, has completed Phase 1 of a nuclear energy options study for the Oil Sands. The conclusions and recommendations of this study address the practical use of nuclear energy in three (3) typical Oil Sands project/energy demand configurations, as defined by PTAC:

1) 120k BPD In-situ (SAGD), constructed in four (4) 30k BPD stages;

2) 100k BPD Mining; and

3) 100k BPD Integrated Mine and Upgrader.

This study has evaluated the currently available Nuclear Power Plants (NPP) that are either in operation or under construction, NPP designs that could be available within a five (5) to seven (7) year period, and the 'next generation' nuclear power plant designs that could be available by 2020. The NPPs are primarily required for producing steam instead of electricity, which is the current form.

None of the contacted NPP vendors provided any significant information beyond what is currently available in the public literature. Since there was no vendor information provided regarding capital cost breakdowns (labour and materials), reliance was therefore placed on reliable published material, and on proprietary SLN information and its NPP design assessments.

Since the study did not provide rigorously estimated capital costs for constructing NPPs in the Oil Sands region, the economic opportunities and risks have not been clearly identified. The current shortage of skilled labour to construct a NPP in the Oil Sands region, coupled with escalating costs resulting from a heated economy, have introduced additional concerns about the implementation of nuclear energy in the Oil Sands region at this time.

The conclusions related to the specifics of this study are:

a) NPPs with water cooled reactors that are either currently available or will be available in near term:

    1) Have thermal capacities greatly exceeding the energy requirements of the three (3) Oil Sands facility configurations considered in the study. For example, the output of the smallest capacity NPP with a water cooled reactor (the CANDU 6E) exceeds requirements for the mining, integrated mining and in-situ scenarios by approximately 1288 MWth/438 MWe, 544 MWth/185 MWe, and 450 MWth/153 MWe, respectively;

    2) Produce steam at a lower pressure than acceptable for in-situ (SAGD) use;

b) High Temperature Gas Reactors (HTGRs) could meet the technical requirements for the three (3) scenarios considered, but are not currently commercialized. Among the considered technologies are the Pebble Bed Modular Reactor (PBMR), and the General Atomics High Temperature Gas Reactor (GA-HTGR). From 10 to 15 years

may be needed before these designs are available for use in the Oil Sands region, assuming that a continuous and concerted effort is applied to their development;

c) The introduction of nuclear energy into the Oil Sands region will be a lengthy and expensive process. The Project duration, including site selection, environmental assessment, licencing and construction could span 11 years for the established CANDU 6E, and could take several years longer for technologies with no licencing experience in Canada;

d) Additional technical and economic information on the NPPs is unlikely to be obtained without issuing Requests for Proposals (RFPs).

General conclusions which can be drawn with respect to the application of nuclear energy in the Oil Sands region are:

1) Deployment of nuclear power in the Oil Sands region based on the currently available NPPs with water cooled reactors would require that surplus energy be converted to electricity and sold to the Alberta power grid, and/or transported as steam or electricity to other Oil Sands facilities. NPPs that are best suited for this purpose are those with the smallest capacities, and of these, the AECL CANDU 6E and the Westinghouse AP1000 represent the lowest risk options. The earliest deployment of nuclear energy in the Oil Sands region is estimated to be 2018.

2) Deployment of NPPs with water cooled reactors for the in-situ (SAGD) application would include steam compressors as an absolute requirement. Although technically feasible, steam compressors are not currently available, and a concerted effort in cooperation with vendors would be required for commercialization. A development period of approximately 50 months would be required to complete the design and testing of a prototype steam compressor. Steam compression would also be required to transport the steam produced over any significant distance.

The principal recommendations resulting from the study are:

1) If the issues identified above are resolved, nuclear energy could in principle make a substantial and long term contribution towards meeting future Oil Sands energy requirements, and reducing the environmental impact of Oil Sands projects. More detailed studies will be required to substantiate the practicality of nuclear energy use for these projects. In particular, a focus on HTGR technology implementation in the oil sands is warranted;

2) A practical way of utilizing the existing commercial NPP designs for use in the Oil Sands region would be to adopt a ‘utility’ approach for the delivery of energy (in the form of steam and electricity) to multiple Oil Sands facilities, and for providing electricity to the Alberta power grid. The licencing and operation of nuclear power plants is unique, and can best be achieved by a dedicated nuclear plant operator. This approach could achieve a higher optimization of the NPPs large thermal output, while addressing the complexity and uniqueness of NPP licencing and operation.

1 Introduction

SNC-Lavalin Nuclear (SLN) is under contract with PTAC to undertake phase 1 of an energy options study that investigates the feasibility of nuclear power in three specific Oil Sands applications. This study includes the evaluation of currently available Nuclear Power Plants (NPPs) and other NPPs that could be available within five to seven years. In addition, an effort was made to identify 'next generation' nuclear power plants that could be available by 2020.

Three reference energy demand scenarios were defined by PTAC as the basis of phase 1 of the Oil Sands energy options study. The energy demands for the three scenarios are summarized in Table 1.

Table 1, Reference Energy Scenarios

Operation	Capacity	Steam Requirements		Electrical Power Requirements
	(bbl/day)	Quantity (lbs/hr)	Pressure (MPa)	MWe
In-Situ (SAGD)	120,000 (Note 1)	4,400,000	8.5 (Note 2)	56
Mining Only (Note 3)	100,000	1,700,000	1	75
Integrated Mining (Note 4)			1	
- mining	100,000	1,700,000		75
- upgrading		1,300,000	2.8 (Note 5)	100
- Total		3,000,000		175
Notes:				
1 - SAGD facilities will be developed in 4 X 30,000 bbl/day phases (Figure 1)				
2 - Pressure at wellhead.				
3 - Mining Only applies to extraction & froth treatment.				
4 - Integrated Mining applies to extraction & froth treatment plus upgrading.				
5 - Three level of steam pressure (2.8 MPa, 1.0 MPa, & 345 kPa) required.				

The reference schedule for the four (4) phases of the reference in-situ project implementation, with each phase consisting of a 30,000 barrel per day facility, is provided in Figure 1. The upper scale indicates the reference in-situ implementation schedule in months. Operation of each of the four (4) phases continues for approximately 25 years.

PTAC indicated further that subsequent Oil Sands developments were not to be considered in this phase of the energy options evaluation, and that the three (3) defined scenarios should be considered independently.

In addition, this study does not consider the integration of the electrical output of the NPPs with the Alberta electrical grid.

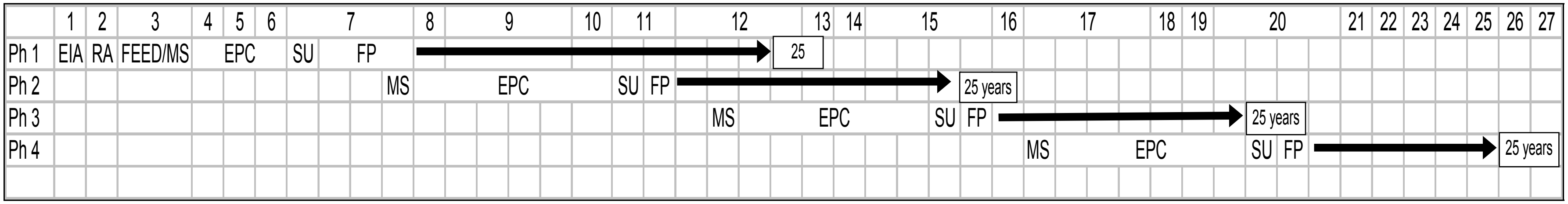


Figure 1, Schedule for In-Situ Implementation

2 Nuclear Power Plant Availability

Nuclear power plants that are currently being offered and that are in operation or under construction are the EPR (AREVA), ABWR (General Electric), and AP1000 (Westinghouse). The above NPPs can be readily adapted to meet Oil Sands siting requirements, and utilize water cooled reactors with outputs in the 3200 MWth to 4500 MWth range. The CANDU 6E NPP is an updated version of the successful CANDU 6 that first entered service in 1982, and can be made available in the designated time frame to meet the Oil Sands siting condition requirements. The earliest operation dates for the first ACR-1000, ESBWR, GA-HTGR, and PBMR units fall outside the specified time frame (2015 or later). These NPPs can meet the Oil Sands siting condition requirements. A brief overview of the available NPPs is provided below. Additional information is provided in Appendix A (overview), and in Appendices B through I (more detailed).

The ABWR offered by General Electric is the latest BWR design to enter service (two units in Japan and two units in Taiwan). The ABWR incorporates significantly advanced safety, operational and maintenance features in comparison with the previous BWR designs. The ABWR is a fully proven NPP. BWR licencing requirements and procedures are well established in more than a dozen countries, including the United States. The ABWR has a Standard Product Licence (SPL) in the US and has been selected for construction in the US by South Texas (not yet committed).

The ACR-1000 currently under development by AECL utilizes a pressure tube reactor and is and represents a substantial departure from the prior CANDU practice. Light water coolant (H_2O) instead of heavy water (D_2O), thicker pressure tubes, larger and thicker calandria tubes, enriched uranium fuel, a new 43 element fuel bundle, new reactivity control devices, higher reactor coolant system and steam system pressures, and a large steel lined concrete containment structure are among the innovations adopted by the ACR-1000 listed by AECL (ref. [11]). The ACR-1000 is not committed for construction.

The AP1000 is the latest PWR NPP offered by Westinghouse. The AP1000 incorporates a high degree of provenness within its nuclear and power production systems, while adopting passive containment and post Loss of Coolant Accident (LOCA) core cooling systems that eliminate the need for safety grade diesel generators. The AP1000 also features a very high degree of modularization, with all modules being shippable by rail or road. PWR licencing requirements and procedures are well established in more than a dozen countries, including the United States. The AP1000 has a Standard Product Licence in the US, has been approved by the European Union, and licenced for construction in China where four (4) units are now under construction.

The CANDU 6E offered by AECL is based on the proven CANDU design with an excellent operating record in Argentina, Canada, China, the Republic of South Korea, and Romania. The first CANDU 6 units entered service in 1982, with the latest CANDU 6 unit entering service in Romania in September of 2007. The CANDU 6E utilizes a full pressure, steel lined concrete containment system, increased redundancy in the service systems, and increased separation of its operational and safety systems. Significant design and licencing efforts would be required prior to a construction commitment. The CANDU 6E is not committed for construction.

The EPR offered by AREVA is licenced for construction in Finland and France. US NRC review of the EPR began in December of 2007. PWR licencing requirements and procedures are well established in more than a dozen countries, including the United States. The EPR design incorporates robust accident prevention and mitigation features. EPR NPPs are currently under construction in Finland and France, and two (2) EPR units were ordered by China on November 27, 2007.

The ESBWR is nearing design completion by General Electric and is in the process of securing a Standard Product Licence (SPL) from the US NRC (anticipated in mid 2009). The ESBWR incorporates passive containment and post LOCA core cooling systems, and offers major operational and maintenance simplifications relative to the ABWR design. The ESBWR will be available within the potential Oil Sands application time frame. The ESBWR is not committed for construction.

The GA-HTGR is not market ready. An aggressive six (6) year design and licencing effort, which can take advantage of prior GA HTGR construction and operating experience and fuel production experience, could yield a construction ready steam generating NPP design. The first GA-HTGR will be a 'first-of-a-kind' (FOAK) NPP. The GA-HTGR is not committed for construction.

The PBMR is not market ready. A direct cycle PBMR demonstration plant with an electrical output of 165 MW is projected to be in operation by PBMR in 2015. However, this date is unlikely to be met (2017 appears to be more realistic). SLN estimates that a minimum of three years will be required following the initial operation of the demonstration PBMR plant to complete the design and licencing (in South Africa) of a commercial direct cycle PBMR NPP. Assuming that licencing activities in Canada proceed in parallel with those in South Africa, the earliest potential date for project commitment is 2020. PBMR is directing minimal effort towards the design of the larger 500 MWth steam generating PBMR. The steam generating version of the PBMR is unlikely to be available for Oil Sands applications before the 2022 time frame. The demonstration PBMR is in the early stages of construction.

The US-APWR offered by Mitsubishi Heavy Industries (MHI) of Japan is a version of the APWR which is designed to meet requirements in Japan, and is directed at the US market. The electrical output of the US-APWR at 1700 MWe is approximately 200 MWe greater than the APWR. MHI submitted an application for standard design certification of the US-APWR to the US NRC on January 07, 2008. MHI licenced the PWR technology from Westinghouse for application in Japan in the early 1960s, and have not constructed a NPP outside of Japan. The APWR and the US-APWR are not committed for construction. Due to the recent MHI submission to the NRC and the lack of specific design information on the US-APWR, the US-APWR is not included in this study. However, it is expected that costs, staff levels and other general data for the US-APWR will be very similar to those for the EPR.

The KSNP (Korean Standard Nuclear Plant) is a de-rated version (electrical output of approximately 1000 MW) of the 1400 MWe CE System 80 NPPs being operated at Palo Verde (three units) by Arizona Power. Eight (8) KSNP units are in operation, and four (4) are under construction in the Republic of South Korea (RSK). The KSNP is also the NPP designated for construction in North Korea, with its robust design and excellent performance record. The Republic of South Korea (RSK) operates both CANDU and PWR NPPs, and has established a common licencing basis for their nuclear plants. The 20 operating nuclear plants in the RSK provide 40% of that country's electricity. However, the RSK has not shown a serious interest in exporting its nuclear power plants. The KSNP is therefore not included in this study.

Other nuclear power plant designs are being discussed by Vendors and quasi research organizations. However, it is very unlikely that any of these concepts will be available for construction within the next 20 years. Such NPPs include AREVA's Very High Temperature Gas Reactor (VHTGR), the Korean Atomic Energy Research Institute VHTGR, the Molten Salt Reactor (a Generation IV concept), the Liquid Metal Fast Breeder Reactor (LMFBR), the System-integrated Modular Advanced Reactor[1] (SMART), and the Hyperion concept. These NPPs are therefore not considered in this study. The reactor designs utilized in US and British submarines were reviewed and determined to be unsuitable for civilian applications (see Appendix P). The Liquid Metal Fast Breeder (LMFB) is the technology preferred by the US Department of Energy (DOE) under the Global Nuclear Energy Partnership (GNEP). While this initiative has been in progress since February of 2006, Canada did not join the program until November of 2007. An overview of the GNEP initiative is provided in Appendix R. The implications and impact of the GNEP initiative on future commercial nuclear power plant employment in Canada is not known. General information on advanced reactor technologies is provided in reference [49].

The future is difficult to predict, given the combination of rapidly expanding world energy demand, and the increasing world wide focus on greenhouse gas emissions. The aggressive pursuit of new nuclear technologies backed by government support could make new reactor technologies available in a relatively short time frame. For example, the US space program began from an almost standing start and a weak technology base to the moon walk within a period of only six (6) years. In comparison, the nuclear technology base for the rapid deployment of advanced nuclear power plant designs is relatively substantial.

[1] KAERI has been developing SMART, a 330 MWth pressurized water reactor with integral steam generators and advanced passive safety features for approximately 20 years. SMART is designed for generating electricity (up to 100 MWe) and/or for thermal applications such as seawater desalination. Construction of a one-fifth scale (65 MWth) SMART plant is nearing completion and scheduled for operation in early 2008. KAERI has not announced plans for the construction of a larger unit.

3 Applicability of Available NPPs to Oil Sands

3.1 Overview

Nuclear Power Plants (NPPs) that are currently available and/or that will be available within five to seven years are considered in this study. These include the ABWR, ACR-1000, AP1000, CANDU 6E, EPR, and ESBWR. The GA-HTGR and PBMR are potentially available in approximately 12 years. Principal features of these NPPs are summarized in Table 2. The ABWR, ACR-1000, AP1000, CANDU 6E, EPR, and ESBWR all utilize water cooled (light water or heavy water) reactors, while the GA-HTGR and PBMR utilize graphite moderated helium cooled reactors. The energy delivered by NPPs operated to date is in the form of steam, which is subsequently utilized to drive a turbine that drives a generator to generate electricity. However, the helium cooled reactors, generically referred to as High Temperature Gas Reactors (HTGRs) have the potential of delivering electricity through a Brayton cycle, where the reactor coolant is utilized to power the turbine that drives the generator, thereby avoiding the need for a steam cycle. An overview of the NPP reactor technologies being considered is provided in Appendix A. Technical summaries for each type of reactor are provided in Appendices B through I. The status of the NPPs considered is summarized in Table 3.

Table 2, Nuclear Power Plants Considered in Study

NPP	Vendor	Reactor Type	Coolant	Moderator	Steam Pressure	Steam Conditions	Size (MWth)
ABWR	GE	BWR	H_20	H_20	7.7 MPa	Saturated	3926
ACR-1000	AECL	Pressure tube	H_2O	D_2O	5.9 MPa	Saturated	3187
AP1000	Westinghouse	PWR	H_2O	H_2O	5.8 MPa	Saturated	3060
CANDU 6E	AECL	CANDU	D_2O	D_2O	4.3 MPa	Saturated	2080
EPR	AREVA	PWR	H_2O	H_2O	7.65	Saturated	4500
ESBWR	GE	BWR	H_20	H_20	7.7 MPa	Saturated	4500
GA-HTGR	GA	HTGR	He	Graphite	17.3 MPa	Superheat	600
PBMR[2]	PBMR	HTGR	He	Graphite	To 17 MPa	Superheat	375

[2] Capacity of PBMR under development is 375 MWth, with a 500 MWth design proposed by PBMR for Oil Sands

Table 3, Nuclear Power Plant Status

NPP	Operating / Construction Status	Licencing Status	Other
ABWR	Four (4) units in operation (Japan and Taiwan)	Standard Product Certification in US	Selected for construction in the US by South Texas but not committed.
ACR-1000	Under Development	Preliminary review by CNSC in progress	Assuming that the FOAK units are ordered within the next four years, the first units could be in operation by 2018
AP1000	Four (4) units under construction in Chjina	Standard Product Certification in US, Design Approval by European Union	The first units in China will be in operation prior to a posible order date for Oil Sands applications
CANDU 6E	Based on proven CANDU 6 units that are operating in five countries. Not committed for construction	CNSC has reviewed the CANDU 6 design but has not approved the CANDU 6E	Design and licensing of the CANDU 6E is not in progress, but can be completed within the schedule provided
EPR	Under construction in Finland and France: orders for two units placed by China	Licenced for construction in Finland, France and China, with review by NRC in progress	The lead project in Finland is behind schedule, and the current projected in-service is late 2011
ESBWR	Detailed design 90% complete	Standard Product Licence from NRC expected in early 2009	Two US utilities have submitted apllications for construction and operation of the ESBWR to the NRC, and the earliest anticipated in-service date is 2015
GA-HTGR	Direct cycle version under development, and no effort on a steam generating version	No licencing activity in place	No plans for construction are in-place., and an in-service date for a demsonstration unit is unlikley before 2020
PBMR	Direct cycle demonstration plant under development	Licencing in progress in South Africa	Projected in-service date for the demonstration plant is 2017

3.2 Current NPP Applications

In current nuclear power plants that are dedicated to electricity production, steam from the Nuclear Steam Plant (NSP) is delivered to steam turbines that drive a generator. The use of nuclear steam for process applications is very limited world-wide, and restricted to low pressure applications such as district heating that does not utilize a significant portion of the NPP output.

In all currently operating NPPs, the steam exhausted from the turbine is condensed by a condenser that is maintained at the lowest feasible vacuum. If a substantial fraction of the NSP output is utilized for electricity production, vacuum condensers are required. Use of a vacuum condenser creates a considerable demand for Condenser Cooling Water (CCW). The water flow required by a ‘once through’ condenser with an eight (8) degree Celsius rise in CCW temperature translates into approximately 3000 kg/sec for each 100 MWth of heat rejected to the condenser. In ‘once through’ CCW applications, the CCW flow can be returned to the water source. If evaporative natural convection or forced draft cooling towers are employed for CCW cooling, the water demand is approximately 44 kg/sec for each 100 MWth of heat rejected, and this water would be lost to the atmosphere. Water cooled NPPs dedicated to electricity production reject approximately 65% of the reactor thermal output to the CCW system.

For example, a single unit AP1000 utilizing evaporative cooling will require approximately 900 kg/sec of cooling water. Although the cooling water can be of fairly low quality, contaminants in the cooling water accumulate in the evaporative cooling system, and must be removed utilizing a water recovery plant.

Water recovered from the Oil Sands applications, either from the processing plant in the case of in-situ applications or as condensate from mining and integrated mining applications, is returned to the NPPs as feedwater following suitable water treatment processes. The treatment of recovered water and requirements for feedwater heating are discussed in Section 21.

3.3 CANDU 6E, ACR-1000 & PWR Specific Considerations

All indirect cycle, water cooled nuclear power plants (see the reactor technology summary in Appendix A), including the CANDU 6E, ACR, AP1000 and EPR, utilize vertical U-tube Steam Generators (SGs) to transfer heat from the reactor coolant that passes through the vertical U-tubes to demineralised light/ordinary (H_20) water on the secondary side of the Steam Generator to produce steam. These Steam Generators require very pure water, with impurities generally measured in parts per million to assure long Steam Generator life. A typical feedwater chemistry specification is provided inTable 4. Evaporator banks supplemented with condensate polishing are capable of treating recovered water from Oil Sands applications and providing feedwater to NPPs that meets these specifications (see also Section 23).

In order to provide assured feedwater quality, all modern NPPs incorporate 100% condensate polishing in the feedwater supply to the Steam Generators, which includes high capacity mixed resin beds. The economics (capital and operating costs) of providing feedwater that meets the required specifications relative to the use of reboilers must be evaluated for each application. Use of reboilers reduces the steam pressure that is available to the Oil Sands application.

Table 4, Typical Feedwater Chemistry Specification

Parameter	Units	Value
Sodium	Mg/kg	<0.002
Chorine	Mg/kg	<0.003
Sulphate	Mg/kg	<0.001
Silica	Mg/kg as SiO_2	<0.020
Conductivity	mS/m	<0.01
Organic Carbon	Mg/kg	<0.1
Total Dissolved Solids	Mg/kg	<0.5
pH	pH	6.0 – 7.5

The vertical Steam Generator configuration employed by the water cooled reactors considered in this study originated from the decision made by Admiral Rickover of the US Navy early in the US nuclear powered submarine program to abandon horizontal Steam Generators for US submarines in favour of vertical Steam Generators. Admiral Rickover's decision was based on his concerns about 'sloshing' when submarines dove or rose to the surface rapidly. However, Russia maintained the horizontal Steam Generator configuration for both their submarines and commercial PWR reactors (the VVER series of plants). Horizontal Steam Generators have the major advantage relative to vertical Steam Generators of avoiding crud/contamination deposits on the tube sheets. Horizontal Steam Generators also avoid a requirement for steam separators, as the steam velocity leaving the water surface is sufficiently low to avoid liquid entrainment. However, dryers are still required. The Russian designed VVER horizontal Steam Generators have an excellent performance record that is much better than the PWR vertical Steam Generators.

Western PWRs such as the EPR or the AP1000, and the pressure tube CANDU 6E and ACR-1000 NPPs can be modified to take advantage of horizontal Steam Generator technology, and to make provision for rapid Steam Generator replacement. This would facilitate a substantial relaxation of feedwater chemistry requirements, thereby reducing capital and operating costs of NPPs in Oil Sands applications. However, the vendors of water cooled NPPs would only entertain such a design modification if assured of a significant market.

3.4 BWR Specific Considerations

The BWR is a direct cycle NPP (see the reactor technology summary in Appendix A) which utilizes the steam generated in the reactor pressure vessel to power the steam turbine (located outside of the containment structure) to drive a generator for electricity production. For the Oil Sands application, a reboiler can be substituted for the steam turbine. Since the BWR steam system is a closed system, the capital and operating costs of a high capacity feedwater treatment facility are avoided. BWRs deliver higher steam pressures than PWR NSPs. However, the available steam pressure from the reboiler is approximately the same as that provided by PWRs.

The delivery of nuclear steam directly from the reactor pressure vessel to the Oil Sands application would serve to increase the available steam pressure, and reduce capital and operating costs. However, reactor coolant has never been permitted to cross the secure site boundary of NPPs, and the likelihood of licencing a facility where the reactor coolant passes through the licenced site boundary is extremely low.

Upon loss of load, the BWR rejects steam to a water filled suppression pool located within the containment, thereby providing reactor fuel cooling. Heat sink requirements are therefore inherent in the existing designs.

3.5 HTGR Specific Considerations

The reference, helium cooled HTGR steam generating nuclear plants (GA-HTGR and PBMR) operate with core outlet temperatures in the 850°C to 900°C range (see the reactor technology summary in Appendix A). In the configurations proposed for Oil Sands applications and in all previous applications, the helium coolant from the reactor is passed though Steam Generators (SGs) to generate superheated steam at pressures of up to 17.3 MPa. These pressures are sufficient to meet all defined Oil Sands energy requirements.

The reference GA design utilizes vertical helical coil ‘once through’ Steam Generators that result in the production of steam with substantial superheat. This superheat facilitates the distribution of steam over significant distances, with steam at the delivery point being either saturated or having some superheat. The reference steam generating PBMR design utilizes horizontal Steam Generators and preheaters, and produces steam in the 11 MPa pressure range.

The HTGRs can accommodate a loss of load (without design modifications) if a condenser is not available. The high heat capacity of the graphite moderator and reflector in the core absorbs heat from the reactor fuel until the backup heat sink is established. Steam rejection to the environment could provide a reliable backup.

HTGRs can be designed in sizes that span the 25 MWth to 600 MWth range. However, the economies of scale related to both capital and operating costs strongly favour the larger units (see Section 24).

An alternate HTGR steam generating arrangement in which a separate superheater and Steam Generator are utilized is shown in Figure 2. In this configuration, the helium coolant from the reactor pressure vessel passes through a superheater that receives saturated steam from a horizontal U-tube Steam Generator with integral preheater. The reduced temperature helium discharged from the superheater passes through the U-tube bundle of the horizontal Steam Generator (SG), and is returned to the reactor helium circuit. Feedwater of relatively low quality, as provided by the Oil Sands water recovery systems, is fed to the preheater section of the SG secondary side where it is heated to saturation temperature and subsequently evaporated. From 10% to 20% of the water supplied to the SG is discharged as blowdown in order to continuously remove contaminants. Heat from the blowdown flow is transferred to the SG feedwater to reduce heat losses. The SG is provided with dryers in order to ensure negligible moisture carry-over into the superheater, thereby minimizing the contamination of superheater tubes. The dryers employed in PWR and CANDU Steam

Generators and in BWRs reduce the moisture content of the steam to below 0.1%. Higher efficiency dryers are feasible. This arrangement can be further investigated during the next phase of this study.

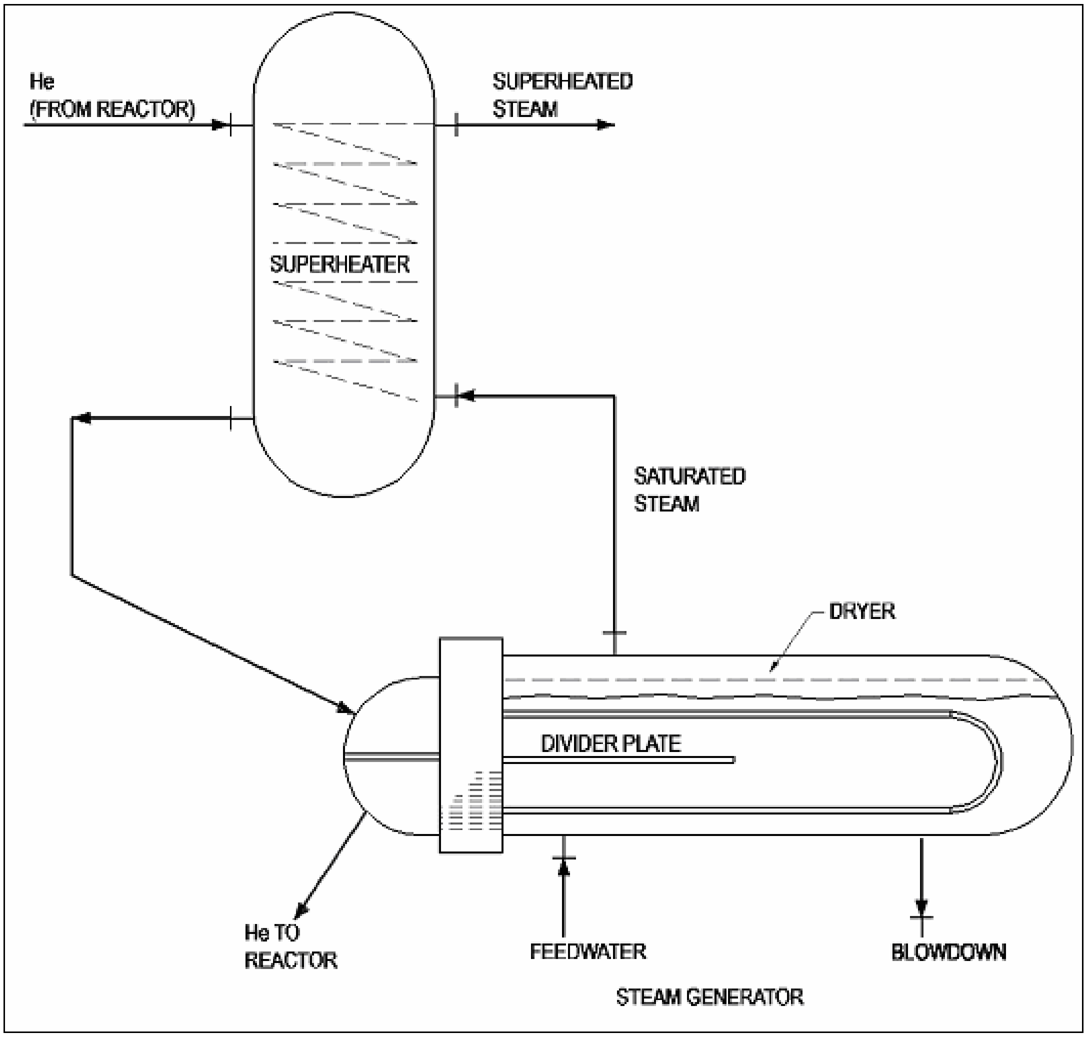


Figure 2, Potential Configuration of HTGR Steam Generation Equipment

4 Nuclear Power Plant Licencing in Canada

4.1 Background

The Canadian Nuclear Safety Commission (CNSC), formerly the Atomic Energy Control Board (AECB), is responsible for licencing all nuclear facilities in Canada, ranging from nuclear power plants and hospital facilities to heavy water production plants and uranium mining and processing facilities.

During the early years of nuclear power deployment in Canada, the AECB adopted a licencing approach that was similar to Great Britain's, whereby it established basic safety and licencing requirements and let the utility/vendor demonstrate compliance. This approach was facilitated by the existence of a single technology and a single vendor, and initially a single utility user in Canada. In contrast, the US NRC adopted a very prescriptive approach to licencing due to the presence of many vendors (B&W, CE, GA, GE, and Westinghouse), the deployment of diverse technologies (PWR, BWR, and HTGR), and employing a number of Architect engineers for NPP design and construction. Over the years, the CNSC and NRC approaches have been converging, with the NRC requiring more from utilities/vendors and the CNSC becoming more prescriptive.

4.2 CNSC Capability

The CNSC, with a total staff of approximately 600, has not licenced a new nuclear power plant since the Darlington NPP (operated by Ontario Power Generation) which entered service in the early 1990s. Since that time, the CNSC sections that are responsible for nuclear power plant licencing have focused on the maintenance of licences for the operating NPPs, and more recently on the refurbishment of existing CANDU facilities. Nuclear power plant refurbishments in Canada will continue over the next 15 years as fuel channel replacement and other refurbishments are required at the Point Lepreau and Gentilly 2 CANDU 6 units, the four (4) Pickering B units, the four (4) Bruce B units, and the four (4) Darlington units. The CNSC, therefore, lacks the resources needed to undertake an aggressive licencing program for a new nuclear power plant design. Linda Keen, the President and Chief Executive Officer of the CNSC until January of 2008 (ref. [9]) stated that:

> *"…in the new power reactor service line, the CNSC's first priority remains the safety of existing facilities. Our second priority is the refurbishment of the current existing fleet of CANDU power plants. The licencing of new nuclear power reactors will need to be third" (reference 9). In the same paper, Ms. Keen stated, with reference to new nuclear power plants, "The impact of such projects would be to dramatically increase the regulatory work of the CNSC. The regulatory oversight of reactor refurbishment and new builds presents an immense challenge for the CNSC. While we are already working on the refurbishments that I have named, and there is that potential for more, the building of new reactors will be an incrementally bigger challenge.*

As I mentioned at last year's winter seminar, the Canadian regulator has not licenced a new nuclear reactor in over 25 years. Consequently, the CNSC has been busy preparing for the development of a regulatory regime for potential new power reactors - one that reflects our modern regulatory regime, regulatory practices and the overall environment in which we operate."

The regulators of countries that were developing countries when nuclear power was first adopted (e.g., Republic of South Korea, Brazil, Taiwan, and South Africa) accepted nuclear power plants that were licenced in the county of origin, and their licencing efforts were largely an educational exercise. In contrast, the CNSC is a knowledgeable organization with a long licencing history. It can therefore be expected that the CNSC will undertake a comprehensive licencing program for any NPP proposed. Since the CNSC knowledge base is focused on conventional CANDU technology, the CNSC must acquire the necessary knowledge base for licencing technologies, such as PWR, BWR, HTGR, or ACR-1000 that are new to Canada. This will require a significant increase in staff with the appropriate background and knowledge base. The level of CNSC effort required to licence a new technology could exceed 500 person-years.

Nuclear power plant licencing in Canada is fee based (ref. [17]). This assures that the CNSC will have the financial resources to acquire the necessary staff, including those who are familiar with BWR and PWR licencing. Such qualified human resources exist in many countries, and can potentially be available to the CNSC. However, with the renewal and expansion of nuclear power programs in several countries, and the effort demanded by the aging nuclear infrastructure in many countries, acquiring sufficient staff will likely be difficult for the CNSC. Training of new staff in the 'Canadian approach' will also be required. Experts in HTGR licencing are difficult to find, and it is expected that the CNSC will need to develop these capabilities together with an in-house knowledge base.

It is unreasonable to anticipate the CNSC being able to expand their technical expertise and staff levels sufficiently to undertake the licencing of two (2) new NPP designs in parallel within a time frame that is consistent with the anticipated Oil Sands requirements.

4.3 General Licencing Considerations

An important characteristic of nuclear power plants is that they cannot be 'shut off' once they have gone critical (sustained a nuclear reaction). Upon loss of load (e.g., loss of line or generator trip), the reactor shutdown system acts quickly to reduce power to a few percent of full power, with the power dropping to below 1% in a few hours. The PWR/CANDU/ACR-1000 designs reject steam to the condenser in the event of a sudden loss of load in order to remove reactor heat until an alternate heat sink is established. An alternate heat sink approach will be required for these plants when operated primarily in a steam delivery mode, in order to ensure reactor fuel cooling upon loss of the steam demand. This could consist of steam discharge to the environment, which is used at OPG's Pickering A NPPs, or the provision of a suppression pool or reject condenser. This will require changes to the licencing documentation, but should not delay the licencing programs.

BWRs reject steam to a suppression pool located within the containment structure upon loss of load, and therefore do not require an additional heat sink. Location of the suppression pool for BWRs within the containment is required, since the steam flows directly from the reactor. In the case of PWRs, the suppression pool can be located outside of containment.

The GA-HTGR has sufficient heat capacity in the graphite core structures to provide a heat sink on loss of load until the back-up heat sinks are established, and therefore does not require an additional heat sink. The PBMR utilizes a resistor bank to dissipate energy and to supplement the heat sink capability of the core.

4.4 Product Specific Challenges

The CANDU 6E design must be subjected to a comprehensive licencing review by the CNSC, and supported by substantial design modifications and analysis by the vendor. However, the CNSC licencing process for the CANDU 6E can take advantage of the CNSC's CANDU knowledge base and prior discussions between the vendor and CNSC, and will require significantly less time than the licencing process for NPP designs that are new to the CNSC. The CNSC has suggested in their latest consultative documents (ref. [8]) that a negative or near zero void reactivity coefficient will be necessary for licencing a new nuclear plant in Canada. Positive void reactivity coefficient is a characteristic of all CANDU reactors, and results in reactor power increasing upon loss of reactor coolant in the absence of shutdown system actions. The CNSC indicated at a consultative meeting hosted by the CNSC directorate on November 29th and 30th, 2007 (which was attended by Andrzej Krukowski, SLN's Chief Nuclear Officer), that licences would not be withheld on the basis of positive void reactivity. As discussed in Section 4.3, an alternate short term heat sink will be required if the condenser capacity in applications that utilize a significant portion of the output as steam does not meet the short term heat sink requirements.

The ACR-1000 is a new design and a substantial departure from the prior CANDU technology. ACR-1000 innovations as listed by AECL relative to the CANDU 6 (ref. [11]) include compact core design, large steel lined concrete containment building, light water reactor coolant (rather than heavy water), thicker pressure tubes, thicker and larger calandria tubes, mechanical zone control rods, enriched fuel, and new fuel bundle design. ACR-1000 licencing will therefore require a substantial effort by the CNSC, and the implementation of new licencing criteria. Although no longer in service, light water cooled and heavy water moderated direct cycle Nuclear Power Plants (NPPs) have been constructed (various SGHWRs, G1, and Fugen). However, there is no experience in the design, operation or licencing of light water cooled and heavy water moderated indirect cycle NPP units. As discussed in Section 4.3, an alternate short term heat sink will be required if the condenser capacity in applications that utilize a significant portion of the output as steam does not meet the short term heat sink requirements.

Major design and development effort by AECL is required to confirm the viability of the ACR-1000 design, including fuel development and nuclear pressure boundary components development.

The PWR and BWR nuclear power plants which have completed rigorous licencing reviews in other countries (US, France, Japan, Finland, Taiwan, or China) are fully compliant with country of origin, client country, international, and IAEA safety requirements. In addition, these plants meet the most recent CNSC published licencing requirements, which have dropped the requirement for two (2) fully capable and independent reactor shutdown systems (ref. [8]). This requirement is not met by the PWR and BWR reactors, and is very difficult to incorporate into these reactors. There is no basis to believe that PWR and BWR NPPs cannot be licenced in Canada. However, a full and lengthy licencing program by the CNSC will be required. As discussed in Section 4.3, an alternate short term heat sink will be required for the PWRs if the condenser capacity in applications that utilize a significant portion of the output as steam does not meet the short term heat sink requirements.

The HTGRs (GA-HTGR & PBMR) employ unique technologies and licencing bases, which are very different from those of water cooled reactors. The CNSC has not licenced a NPP employing HTGR technology. However, HTGRs have been licenced in the US and Germany, and a construction licence has been issued for a 400 MWth pebble bed HTGR in China (projected in-service date of late 2011). Research HTGRs are licenced and operating in Japan and China, and a demonstration pebble bed HTGR is currently undergoing licencing in South Africa. In addition, the MAGNOX and AGR gas cooled (CO_2) NPPs are licenced and continue to be operated in Great Britain. A major component of HTGR licencing will be the qualification of the fuel fabrication processes. Unlike water cooled reactor fuel elements consisting of uranium oxide pellets housed in zirconium alloy cylinders with welded end caps (amiable to standard manufacturing and inspection processes), TRISO particles are made using an extrusion process to produce the uranium oxide core of the particle, where the multiple coatings are applied to the kernel in fluidized beds. This process is unique to the TRISO fuel (see Appendix A). The production of reactor quality TRISO fuel has always proven to be a challenge.

There is no reason to believe that the HTGR NPPs cannot be licenced in Canada.

4.5 Licencing Schedule

The overall licencing schedule is dependant on many parameters, including the NPP technology and the site location. Figure 1 shows an aggressive nuclear implementation schedule that encompasses the adoption of a water cooled reactor technology that is new to Canada. The prerequisites for a construction licence include site selection, site qualification, environmental assessment, and sufficient licencing review to ensure there are no major obstacles to licencing the NPP.

A generic licencing phase (see Figure 25) will be required for any technology that is new to Canada and the CNSC, and will provide the CNSC with time to acquire staff and develop the knowledge base necessary for licencing a new technology in Canada. It is anticipated that research and development efforts would be limited for those NPPs having completed rigorous licencing procedures in other countries, and would likely be greatest for technologies with substantial innovations such as the ACR-1000 and HTGRs.

An aggressive project implementation schedule for the CANDU 6E is presented in Figure 26. Generic licencing, and research and development activities, are not required for the CANDU 6E due to its extensive use of proven systems and components. In addition, the durations of other activities are shortened.

Repeat units at the same site, if constructed with not more than two (2) years between construction starts, will avoid the time required for site selection, site qualification and environmental assessment, and the generic and early licencing activities. Schedules for repeat units at the same site are therefore set by the procurement and construction activities.

5 Vendor Capabilities

5.1 AECL

5.1.1 Background

AECL was split from the National Research Council in the early 1960s, after which time AECL focused on development and deployment of the heavy water cooled and heavy water moderated natural uranium fuelled pressure tube CANDU reactor technology. AECL efforts were initially directed towards meeting Ontario's electricity production demands. AECL designed the very successful CANDU 6 in the late 1970s, with four (4) first generation CANDU 6 units entering service in Quebec, New Brunswick, the Republic of South Korea, and Argentina, in 1982 and early 1983. Since then, seven additional CANDU 6 units have entered service, with the latest units being two (2) Qinshan units in China (2002 and 2003), and Cernovoda 2 in Romania which entered service in September of 2007. AECL efforts to export CANDU nuclear power plants on a commercial basis began with the development of the CANDU 6 design.

5.1.2 Capabilities

The CANDU 6 design has been the standard AECL offering for over 30 years. AECL has not licenced or constructed a 'new' nuclear power plant design since the introduction of the first generation CANDU 6 units in the late 1970s. However, AECL does maintain a large research organization that employs approximately 2200, and a design and service organization that employs approximately 1100. AECL is currently developing the ACR-1000 design.

AECL's current offerings are the CANDU 6E and the ACR-1000. The CANDU 6E is based on the proven CANDU 6, and incorporates many enhancements directed at meeting current regulatory (CNSC) requirements and accepted international practices, while retaining the proven reactor and power production systems. A significant design and licencing effort that is consistent with AECL's experience and capability will be required in order to obtain a construction licence for the CANDU 6E.

The ACR-1000, due to its extensive innovation and new technology base, will require significant time to demonstrate performance and licencability. AECL did not provide information on the development programs in place to support the ACR-1000 design.

AECL has limited manufacturing capability and relies on nuclear industry vendors for the supply of components.

AECL is a crown corporation with significant reliance on financial support through funding from the Government of Canada for product development and project implementation.

5.2 AREVA

5.2.1 Background

AREVA, which was formed from the integration of Siemens Nuclear Division (Germany) and Framatome (France), has designed and constructed more nuclear power plants world-wide than any other organization. The PWR water cooled reactor technologies employed by Framatome were licenced from Westinghouse. Siemens has designed and constructed Pressurized Water Reactors (PWRs) based on the licenced Westinghouse technology. Siemens' Boiling Water Reactors (BWRs) are based on licenced GE technology, and their heavy water cooled pressure vessel reactors are based on in-house technology. Framatome has focused on PWRs and have constructed plants in the 600 MWe, 900 MWe, 1200 MWe, and 1400 MWe size ranges. AREVA has developed the EPR, which is a PWR in the 1600 MWe class. EPR NPPs are currently under construction in Finland and France and have been ordered by China (two units). Review of the US-EPR by the US Nuclear Regulatory Commission (NRC) began in late 2007. AREVA projects the in-service date for the first US EPR as being mid 2015.

5.2.2 Capabilities

AREVA has a strong and substantial current design and project execution capability. AREVA operates with major manufacturing capabilities, and produces most of the heavy nuclear components (Steam Generators, pressure vessels, etc.) for their nuclear plants in France. AREVA has also formed partnerships with companies in the US and China that are capable of manufacturing large nuclear components. AREVA is a major supplier of fuel for PWR and BWR NPPs, and is a major supplier of NPP services world-wide.

AREVA is a large organization with substantial financial capability.

5.3 General Atomics

5.3.1 Background

General Atomics (GA) acquired the basic High Temperature Gas Reactor (HTGR) technology through the Dragon project, a cooperative effort of thirteen OECD countries executed in England in the 1950s. GA designed the very successful Peach Bottom 1 (US) demonstration HTGR, and the only US commercial HTGR located at Fort St. Vrain, Colorado. Construction of the Fort St. Vrain HTGR began in 1968, with the first electricity delivered to the grid in 1976. Fort St. Vrain was shut down in 1989 and has since been decommissioned. General Atomics also manufactured the fuel for Fort St. Vrain. GA has also designed and continues to supply the TRIGA research reactors. GA has a proven record for 'first-of-a-kind' (FOAK) projects in a wide range of fields. Its largest major commercial success, although not nuclear, is the Predator drone that is widely deployed by the US military.

5.3.2 Capabilities

General Atomics has maintained a strong HTGR design capability, having completed the conceptual design of the New Production Reactor (NPR) in the early 1990s, and is continuing with the development of a direct cycle HTGR in collaboration with Russian and French partners. Preliminary design of the GT-MHR (600 MWth) direct cycle plant was completed in early 2007.

General Atomics does not have a market-ready HTGR design, and is not devoting any effort to the design of a modern steam generating NPP. However, GA has the experience, technology base and expertise to efficiently execute such a design. Approximately six (6) years would be required for General Atomics to have a HTGR design that is construction ready. Licencing could proceed in parallel with the last three (3) years of design effort. Manufacture of the TRISO based fuel is critical to HTGR deployment. The fuel manufacturing facility that produced fuel for Fort St. Vrain is still available at GA, and can be made operational in a relatively short time.

General Atomics is a privately owned company with very limited financial capability, and is very small in comparison with large organizations such as AECL, AREVA, General Electric and Westinghouse. General Atomics will therefore need to partner with other companies and/or receive substantial client funding in order to complete the GA-HTGR design and proceed with the procurement and construction of GA-HTGR plants.

General Atomics has limited manufacturing capability, and relies on nuclear industry vendors for the supply of components.

5.4 General Electric

5.4.1 Background

General Electric pioneered the BWR design concept and has continuously advanced the BWR technology since its commercial introduction in the 1960s. GE BWR technology was licenced to Toshiba and Hitachi for application in Japan, and to KWU in Germany. GE and Hitachi formed a partnership in 2007 to market BWRs world-wide. The latest GE BWR design to enter service is the 1400 MW class ABWR, which is now in operation in Japan and Taiwan (two units in each country). The ABWR has been selected for construction in the US by South Texas, largely based on it having a Standard Product Licence in the US and a proven construction and operating record.

GE is currently in the process of obtaining a Standard Product Licence for the 1600 MW class ESBWR in the US, which introduces major design simplifications that include passive containment and core cooling systems relative to the ABWR.

5.4.2 Capabilities

General Electric has a strong and current design capability, and is a major supplier of nuclear fuel. GE has limited manufacturing capability except for fuel, and relies on nuclear industry vendors for the supply of components other than fuel. Both GE and Hitachi have Turbine-Generator manufacturing facilities, and Hitachi has major nuclear component manufacturing facilities located in Japan that are capable of manufacturing BWR pressure vessels and other components.

Both General Electric and Hitachi are very large companies with substantial financial capabilities.

5.5 PBMR

5.5.1 Background

Germany acquired the basic High Temperature Gas Reactor (HTGR) technology through the Dragon project; a cooperative effort of thirteen OECD countries executed in England in the 1950s, and constructed the very successful AVR-15 demonstration plant and the THTR-300 commercial plant. The THTR-300, which was designed to operate on a thorium fuel cycle, entered commercial service in 1985 and was shut down in 1989 as a result of political will. However, there were no significant technical problems encountered during THTR-300 operation.

The PBMR organization in South Africa, a company formed in the 1990s, acquired the basic Pebble Bed reactor technology from Germany. Current design efforts at PBMR are focused on the design of a direct cycle Pebble Bed Reactor (PBMR) with an output of approximately 165 MWe, although some effort has been directed towards a larger 500 MWth steam generating version.

PBMR has completed construction of a demonstration plant for the production of TRISO fuel particles and fuel pebbles. The first operation with uranium feedstock is anticipated in early 2008.

Westinghouse recently acquired a financial interest (extent not known) in the PBMR organization, and has purchased a small engineering company in South Africa. The role of Westinghouse, and their engineering and contractor partner the Shaw Group (a 20% owner of Westinghouse) in future PBMR efforts has not been made public.

The in-service date of 2015 that is currently projected for the PBMR direct cycle demonstration plant is optimistic, with 2017 being a more realistic date. A design and licencing effort spanning at least three (3) years will be required following start-up of the PBMR demonstration plant to have a commercial design ready for commitment. Approximately five (5) years of design and licencing effort following start-up of the PBMR demonstration plant will be required to design and licence a steam generating version of this plant. A PBMR that is suited to Oil Sands applications is therefore unlikely to be available before approximately 2022. However, an aggressive effort by the Shaw-Westinghouse organization could advance this date considerably. Oak Ridge National Laboratories (ORNL) in the US recently invited 'Expressions of Interest' for the design, construction and operation of an HTGR dedicated to hydrogen production. GA and Shaw-Westinghouse have received US Department of Energy (DOE) contracts in late 2007 for initial conceptual design efforts. Substantial funding from ORNL has the potential for advancing the PBMR implementation schedule.

5.5.2 Capabilities

The PBMR organization has no prior experience with the design and construction of nuclear power plants, and the South African regulator has not previously licenced a nuclear power plant independently. Nuclear experience in South Africa is limited to the construction and operation of two 1000 MW class PWRs supplied by Framatome. PBMR currently has no experience in producing TRISO or Pebble fuel, although commissioning of a demonstration fuel fabrication plant is nearing completion. PBMR has no manufacturing capability, and relies on nuclear industry vendors for the supply of components.

PBMR is largely owned by the government of South Africa, and currently relies on government funding of the PBMR development effort. Westinghouse recently purchased an interest in PBMR, and has the potential for adding financial strength to the organization.

5.6 Westinghouse

5.6.1 Background

Westinghouse is the pioneer in developing the PWR technology used for US submarine and aircraft carrier propulsion, and is the dominant commercial nuclear technology used world-wide. Westinghouse licenced their PWR technology to Mitsubishi for application in Japan, to Framatome of France, to KWU of Germany, and most recently to Great Britain. Westinghouse acquired the nuclear division of Combustion Engineering approximately six (6) years ago. Combustion Engineering was the second largest PWR vendor in the US, and the designer of the 1000 MW Class Korean Standard Nuclear Plant (KSNP) which is based on the System 80 NPPs currently operating at Palo Verde in Arizona. The KSNP is the principal NPP (eight units) operating in the Republic of South Korea (RSK), with an additional four (4) KSNP units under construction. Four (4) 1400 MW Class NPPs based on CE PWR technology are committed for construction in RSK, with construction starting between June of 2008 and March of 2012.

Westinghouse was recently acquired by Toshiba, a major BWR and BWR fuel supplier based in Japan. Toshiba subsequently sold a 20% financial interest in Westinghouse to the Shaw Engineering Group. Shaw is a very large organization with nuclear power plant engineering and construction experience. The latest Westinghouse NPP, designated the AP1000, has a Standard Product Licence in the US and approval by the European Union, and is currently in the early stages of construction in China (four units). The AP-1000 design is readily adaptable to Oil Sands conditions.

5.6.2 Capabilities

Westinghouse has integrated the nuclear operations of Combustion Engineering into its organization. Westinghouse can take advantage of broad based industry participation in product design, and has a strong and broadly based current design capability. Westinghouse has a limited manufacturing capability and relies on nuclear industry vendors for the supply of components. However, Toshiba has major manufacturing facilities in Japan that are capable of producing PWR pressure vessels and other nuclear power plant components, and turbine generators. Toshiba is also a producer of nuclear fuel. The Shaw Group's ownership of 20% of Westinghouse adds strong engineering and construction expertise.

Westinghouse, through its Toshiba ownership, has substantial financial capability.

6 Electricity Production in Cogeneration Facilities

All nuclear power plants are capable of cogeneration (electricity production and process heat delivery). Traditionally, nuclear power plants have produced electricity by passing the steam they produce through steam turbines (consisting of high and low pressure turbines) that discharge into a condenser that is maintained under the maximum feasible vacuum. The cost of the low pressure (LP) turbines, condensers, and Condenser Cooling Water (CCW) systems is substantial.

For cogeneration applications, there is a significant economic advantage from the utilization of back-pressure turbines to the extent feasible. In this configuration, steam from the nuclear steam plant (NSP) passes through a back-pressure turbine which drives a generator, with the steam from the turbine discharge utilized for process applications. Since the steam pressures delivered by the water cooled reactors are relatively low, the fraction of energy available for electricity generation in this configuration is limited by the need for turbine steam discharge pressure to be sufficiently high for meeting minimal process heat requirements. For example, for every 100 MWth of 5.8 MPa steam supplied to a turbine with an exhaust pressure of 2 MPa, approximately 7 MW of electricity is produced. The turbine exhaust, with approximately 89% quality (11% moisture), is available for process applications. Hence, a NPP with a thermal output of 3000 MW would have a net electrical output (after allowance for station loads) of approximately 175 MW.

Although not currently available, a three (3) stage turbine arrangement (high pressure, medium pressure and low pressure) in which the medium pressure turbines are operated as back pressure turbines is feasible, and within the current technological capability. Although optimization is required, this configuration could increase the electrical output by a factor of two (2) or more in a cogeneration configuration.

Additional flexibility for cogeneration energy production is available with the HTGRs. This results from the helium behaving essentially as an ideal gas rather than a condensing fluid, and from the high reactor pressure vessel outlet temperature (up to 540 ^{o}C). The helium from the HTGR can be passed through a helium turbine (direct cycle) that drives the generator, with the helium from the turbine utilized to generate steam. As shown in Figure 3, for the reference 600 MWth GA-HTGR design, a net electrical output of approximately 160 MW is available (after allowance for station loads), and approximately 280 MWth can be generated as steam at 13.8 MPa. In practice, the ratio of electricity production to steam production for HTGRs can vary over a very wide range. However, if a relatively small fraction of the energy is utilized for electrical production, economics favour the use of a small helium turbine operating in parallel with the steam generation unit. The PBMR can also be operated in the cogeneration configuration, as described above.

Avoiding the use of a condensing turbine and the need for large LP turbines, condensers and condenser cooling water systems is particularly important in the Oil Sands regions of Alberta, due to the relatively limited water supplies. Cooling towers are problematic in very cold weather conditions due to the water freezing.

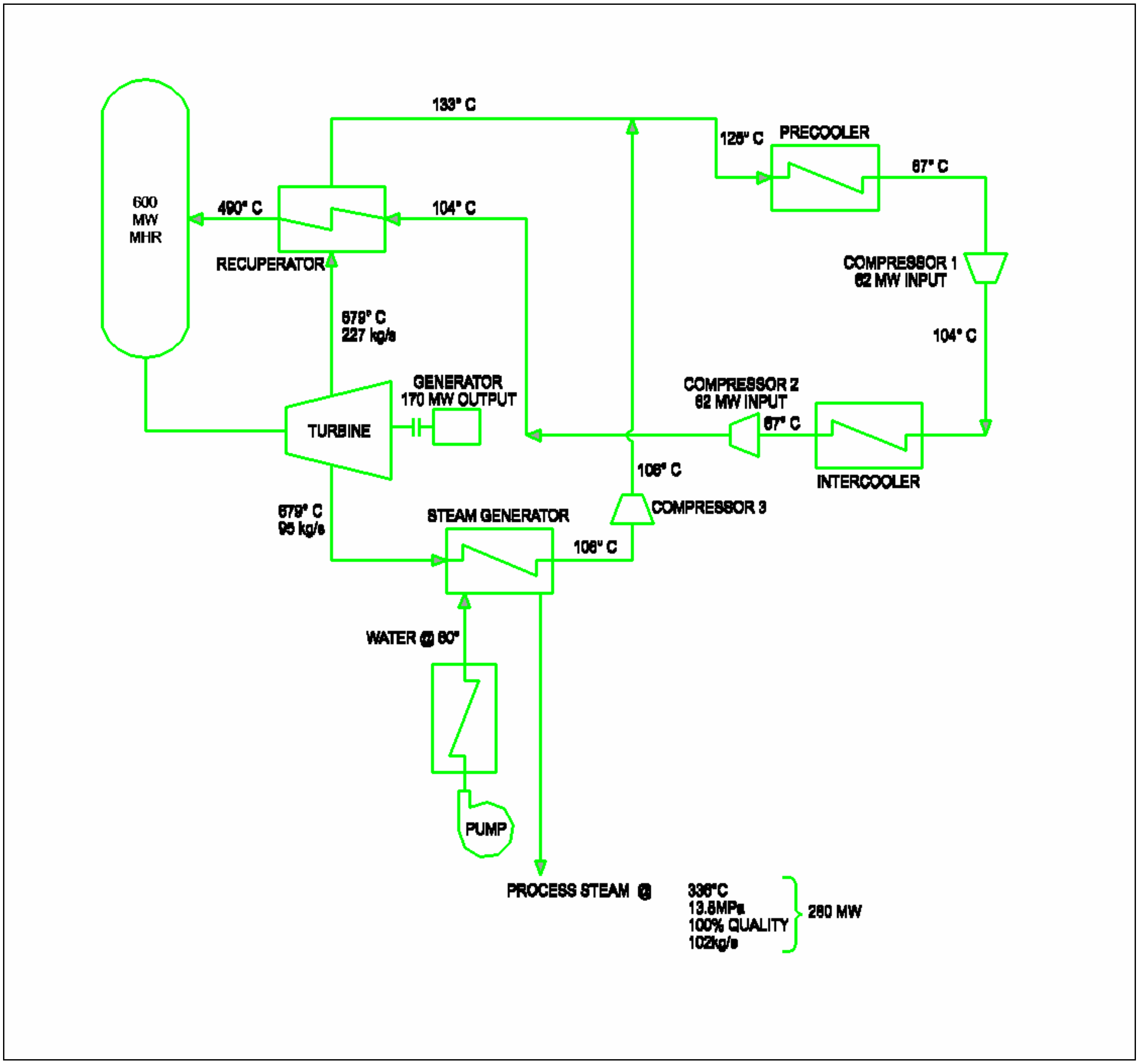


Figure 3, Potential Cogeneration Cycle for GA-MHTGR

7 Steam Distribution

7.1 Background

The distribution of steam from a nuclear power plant over a defined area is required in order to serve the Oil Sands energy user demand. The capacity of a nuclear generation facility that is technically viable is increased with the technically and economically feasible distribution area. The technically feasible steam distribution area is a function of both the available steam supply pressure and temperature provided by the NPP, and the steam pressure required by the Oil Sands operator.

An alternative to steam distribution is the distribution of electricity and the generation of steam utilizing electric boilers at the user locations. This approach is costly, since between 60% and 65% of the thermal energy produced by a NPP is rejected to the environment in the generation of electricity: in addition, and the electrical distribution system and electric boiler costs can be substantial.

7.2 Steam Distribution for In-Situ Applications

The in-situ applications require steam pressures at the well head in the range of 8.5 MPa (see Table 1). Significantly higher steam pressures at the NPP, depending on the distribution distance and the pipe sizes employed, are required to facilitate steam distribution.

Steam line pressure loss calculations indicate that it is technically feasible to distribute steam over a radius of 150 km or greater, if the initial steam conditions are sufficiently high. For example, with steam at 17 MPa and 540 ^{o}C provided by the NPP, steam conditions at the well head location are approximately 10 MPa at saturated conditions, if 1.1 million pounds of steam per hour are transported through a 24 inch diameter line over a 130 km distance. Additional information regarding pressure losses incurred over distances for various pipe sizes with initial pressures of 17 MPa and 12 MPa is shown in Figure 4. Similar information is presented in Figure 5 for steam flows of 1.4 million pounds per hour. Supporting data is provided in Attachment A. In cases where a small amount of moisture is present in the steam at the Oil Sands user's location, the moisture can be readily removed by steam separators if required.

The capital cost of steam distribution piping increases significantly for design temperatures above approximately 475 ^{o}C, since materials with high temperature capability have higher costs than more standard materials for temperatures of up to 475 ^{o}C. Therefore, de-superheaters, which consist of devices that spray a water mist into the steam flow, would be employed where appropriate. De-superheaters serve to increase steam mass flow, and to reduce steam temperature.

Optimization of the HTGR design for the steam generating application, and the need to remove heat from the reactor core (which has core outlet temperatures above 850 ^{o}C) results in steam generation pressures in the range of 17 MPa, and temperatures in the range of 540 ^{o}C. The enthalpy of steam is relatively independent of pressure over the 10 MPa to 17

MPa range, but is strongly dependant on temperature. The HTGRs are therefore suitable for in-situ applications.

The water cooled reactors deliver steam at saturated conditions and at pressures that range from 4.6 MPa to 6 MPa. Hence the energy must be upgraded (pressure increased) if the water cooled reactors are to serve in-situ applications. Two (2) potential options for upgrading the energy from water cooled reactors are steam compressors, and electric boilers.

Steam compressors, when driven by a steam turbine, can increase the steam pressure sufficiently to accommodate line pressure losses and meet in-situ application requirements. Steam compressors are technically feasible but are not currently available (see Section 10).

Electric boilers that are located at the in-situ application location and that utilize electricity generated by water cooled reactors to generate steam at sufficient pressure for the in-situ application may be economic, providing that water cooled reactors produce energy at a cost that is sufficiently below the HTGRs. Approximately 65% of the thermal output of NPPs utilizing water cooled reactors is rejected to the environment during the electricity generation process. Transmission line losses and the overall thermal efficiency of the electric boiler facility will further reduce the energy available to the in-situ application.

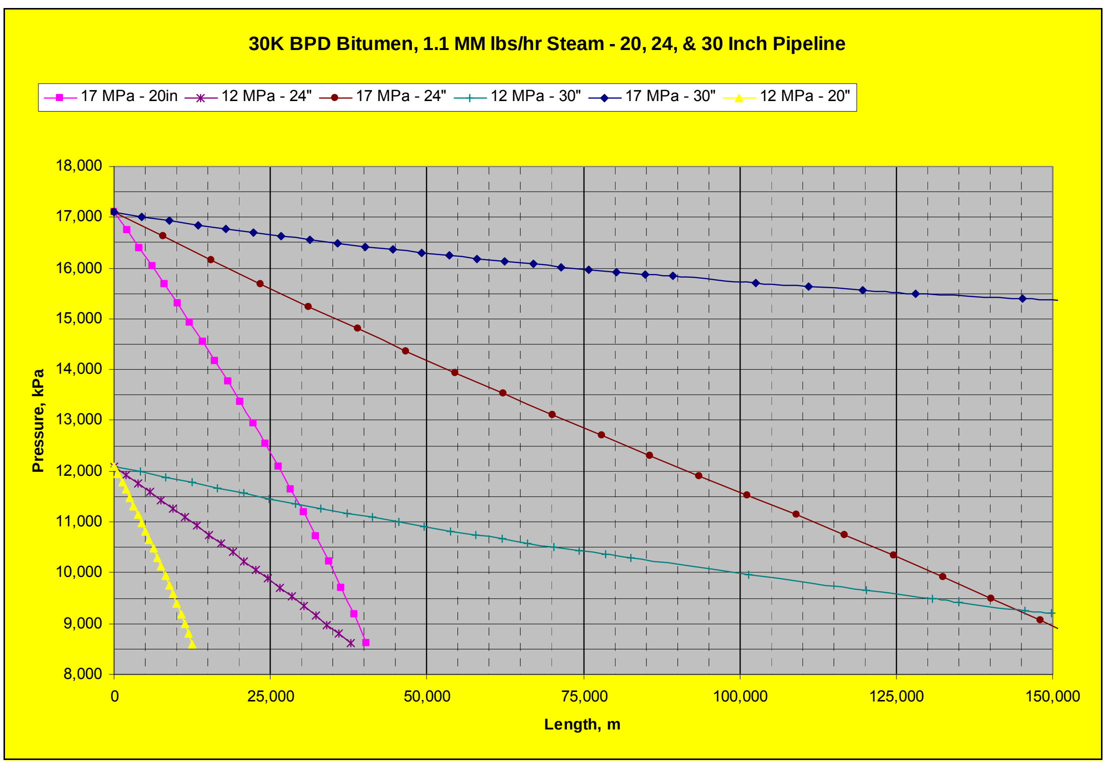


Figure 4, Pipeline Pressure Losses for In-Situ Applications (17 MPa)

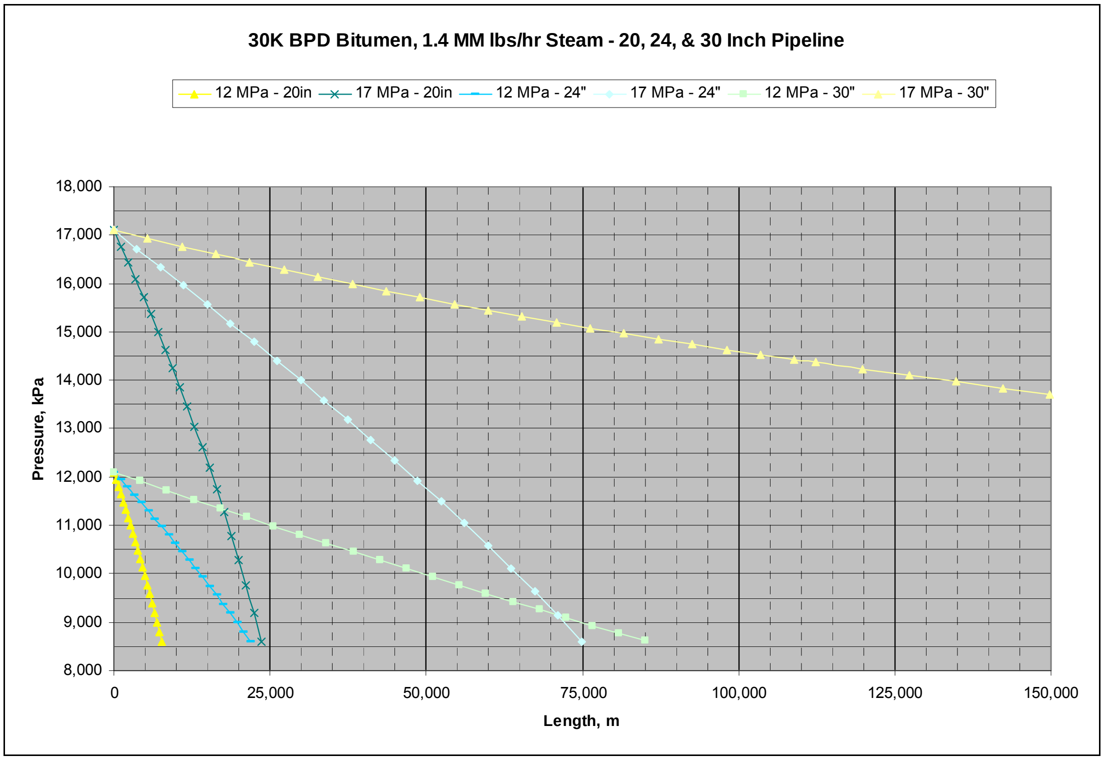


Figure 5, Pipeline Pressure Losses for In-Situ Applications (12 MPa)

The approximate cost of steam distribution piping based on the NPP steam delivery pressure of 17.3 MPa at a temperature of 475°C is provided in Table 5. This cost represents the total in-place cost that includes support structures, installation, insulation, hydrostatic testing, and commissioning. Optimization is required for each application.

The HTGRs offer a wide range of steam distribution options for both mining and in-situ applications without requiring steam compressors and/or electric boilers. The NPPs with water cooled reactors can serve both mining and in-situ applications if steam compressors and/or electric boilers are utilized.

Table 5, Steam Distribution Line Costs

Line Size	Cost ($M/km)
36” line	5.7
30” line	4.8
24” line	3.8

The Oil Sands deposits of Alberta are distributed over a relatively small area in the north (see Section 8). Therefore, the potential exists for three (3) or four (4) multi-unit stations to meet all the in-situ oil extraction and processing requirements. The economics of multi-unit stations, including flexibility of operation, must be evaluated relative to the cost of steam distribution system piping.

7.3 Steam Distribution for Mining & Integrated Mining Applications

The mining and integrated mining applications require steam pressures that are low relative to the in-situ applications. Hence, the distribution of steam at relatively low pressures that is consistent with requirements for mining and integrated mining operations is feasible.

However, with the pressures available from water cooled NPPs (from 4.6 MPa to 7.6 MPa), the practical distribution distances are limited to approximately 50 km for mining operations, and 25 km for integrated mining operations (see Figure 6 and Figure 7). The initial pressure of 5.8MPa was selected for the analysis, since this pressure is approximately the steam pressure available from PWRs, ACR-1000, and BWRs at the reboiler discharge. Distribution distances for the CANDU 6E can be approximated from Figure 5 and Figure 6 by examining the distance to the right of the 4.6 MPa line intersections with the pressure curves.

The steam distribution distance for NPPs utilizing water cooled reactors may be increased by the use of steam compressors (see Section 10). Energy can also be transmitted as electricity, with steam generated at the user location utilizing electric boilers. It is technically feasible to distribute steam over distances of 300 km or more to serve the mining and integrated mining applications. However, the analysis limited the distribution distances to 150 km, which is believed to be a practical limit.

Since the bitumen deposits available for extraction and recovery by mining are located within a relatively small area, it may be feasible to serve the steam demands for mining and integrated mining using a small number of multi-unit nuclear power stations. It may also be feasible to meet a portion of the mining and integrated mining application requirements using NPPs that are located for the optimized distribution of steam to in-situ applications. Supporting data is provided in Attachment A. In cases where moisture is present in the steam at the Oil Sands user’s location, the moisture can be readily removed by steam separators if required.

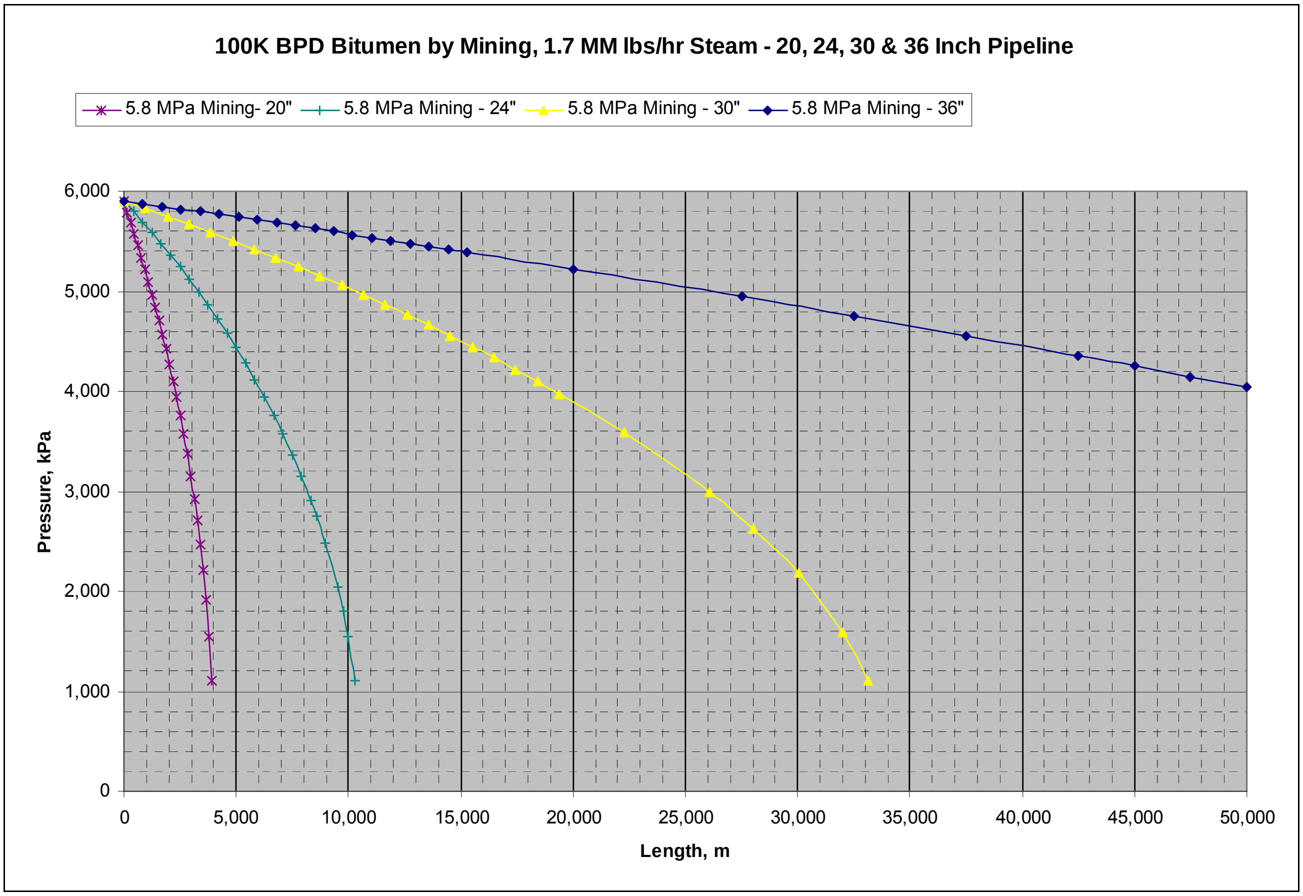


Figure 6, Pipeline Pressure Losses for Mining Applications

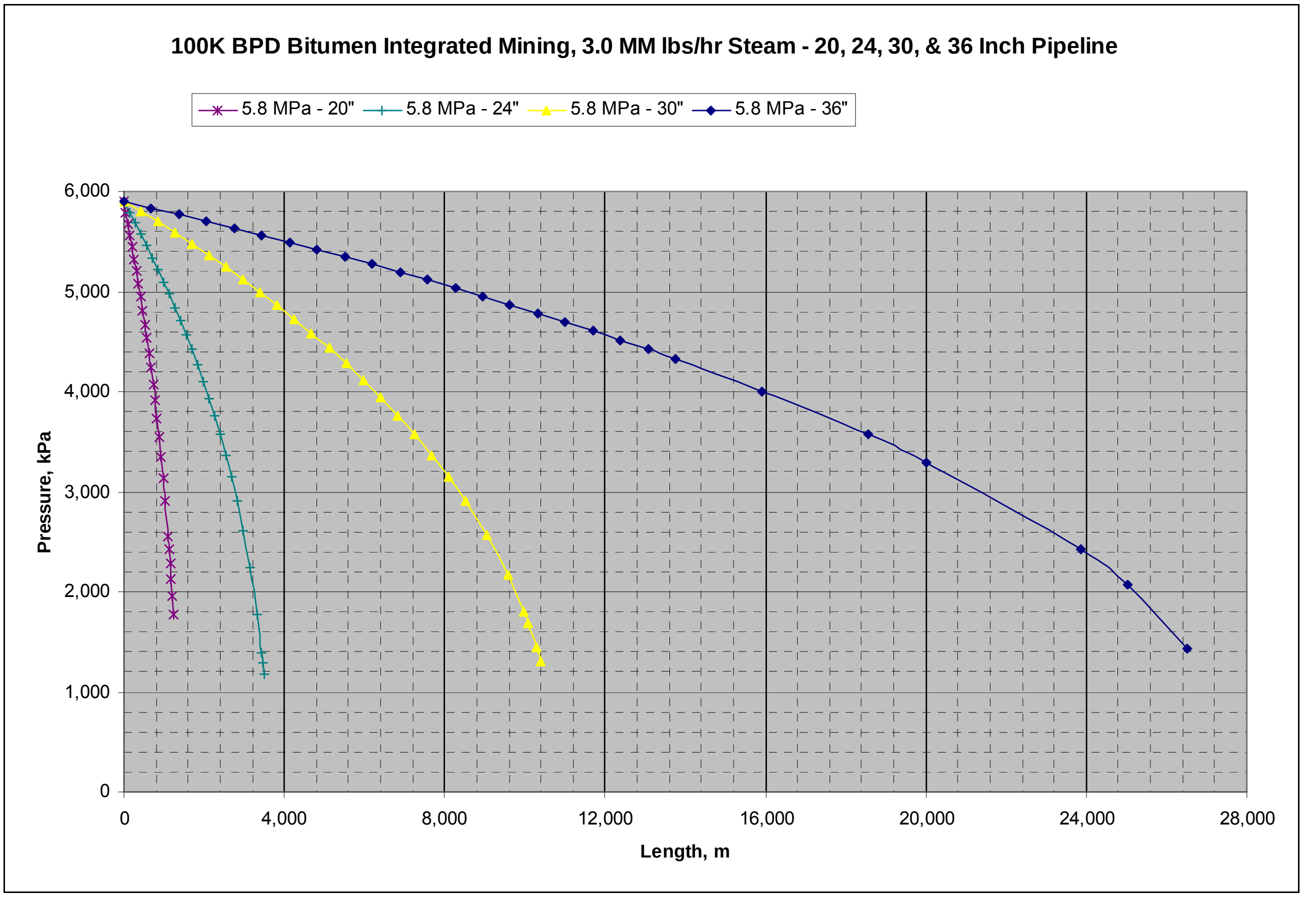


Figure 7, Pipeline Pressure Losses for Integrated Mining Applications

7.4 Recovered Water & Condensate Return

Approximately 90% to 95% of the steam provided to the in-situ application is recovered during the processing of the recovered bitumen. The recovered water is processed and utilized as feedwater to the NPPs. The processing of recovered water is discussed in Section 21. Make-up of the water lost in the bitumen recovery process is made up from a water treatment plant.

In the case of mining and integrated mining applications, the majority of the steam supplied to the applications is recovered as condensate. This condensate must be returned to the NPPs through suitable water treatment facilities.

8 Oil Sands Resource Distribution in Alberta

Approximately 80% of Alberta's Oil Sands resources require in-situ technologies for their recovery, while approximately 20% can be recovered by mining operations. The Alberta Oil Sands Resource Map shown in Figure 8 indicates that a majority of bitumen deposits are located within a relatively small area of northern Alberta. The Oil Sands bitumen resources that are available for extraction by mining cover approximately 1/3 of the in-situ resources area.

An overview of projects that are in place and planned for the Oil Sands regions is provided in Figure 9 (extracted from ref. [48]).

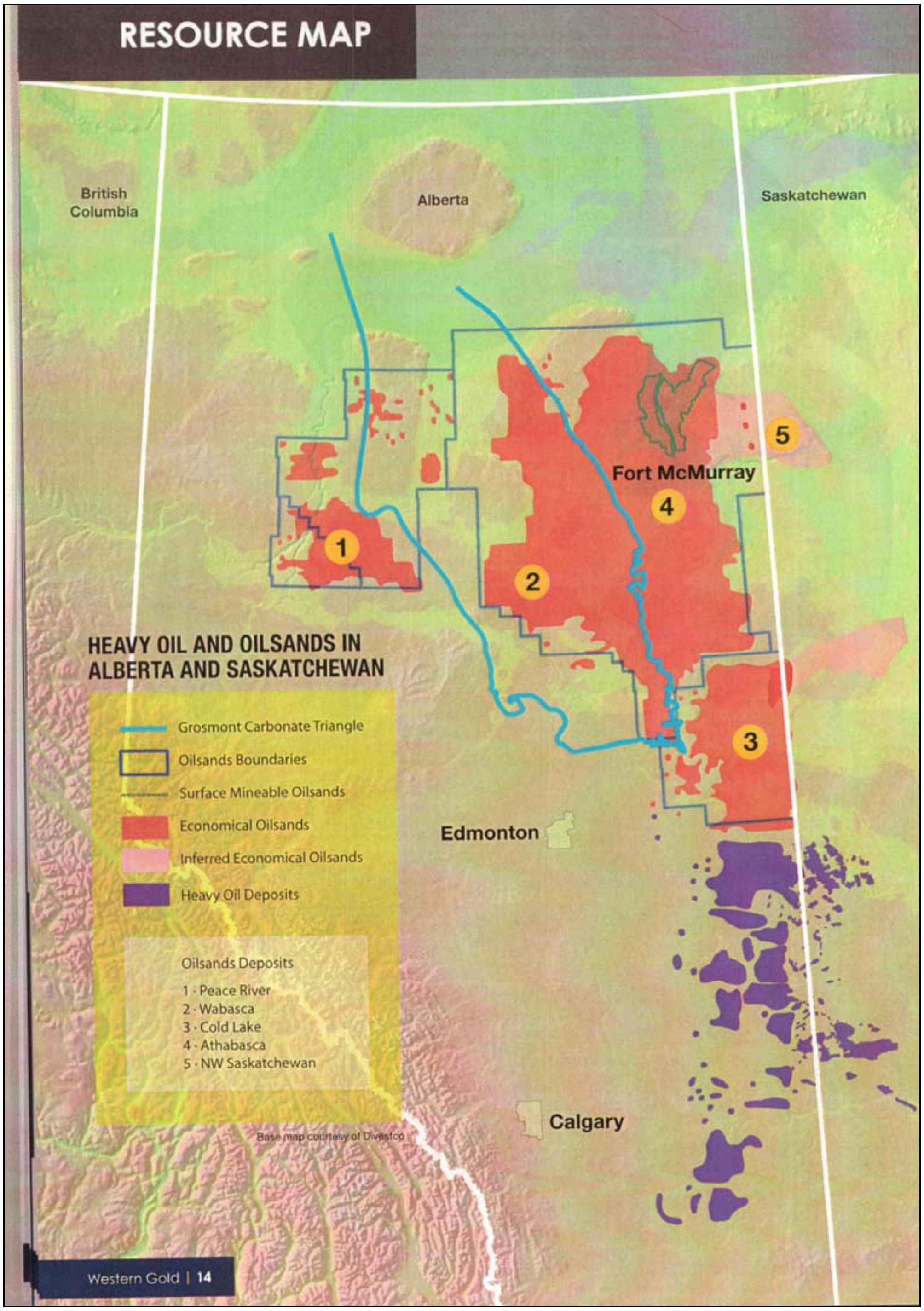
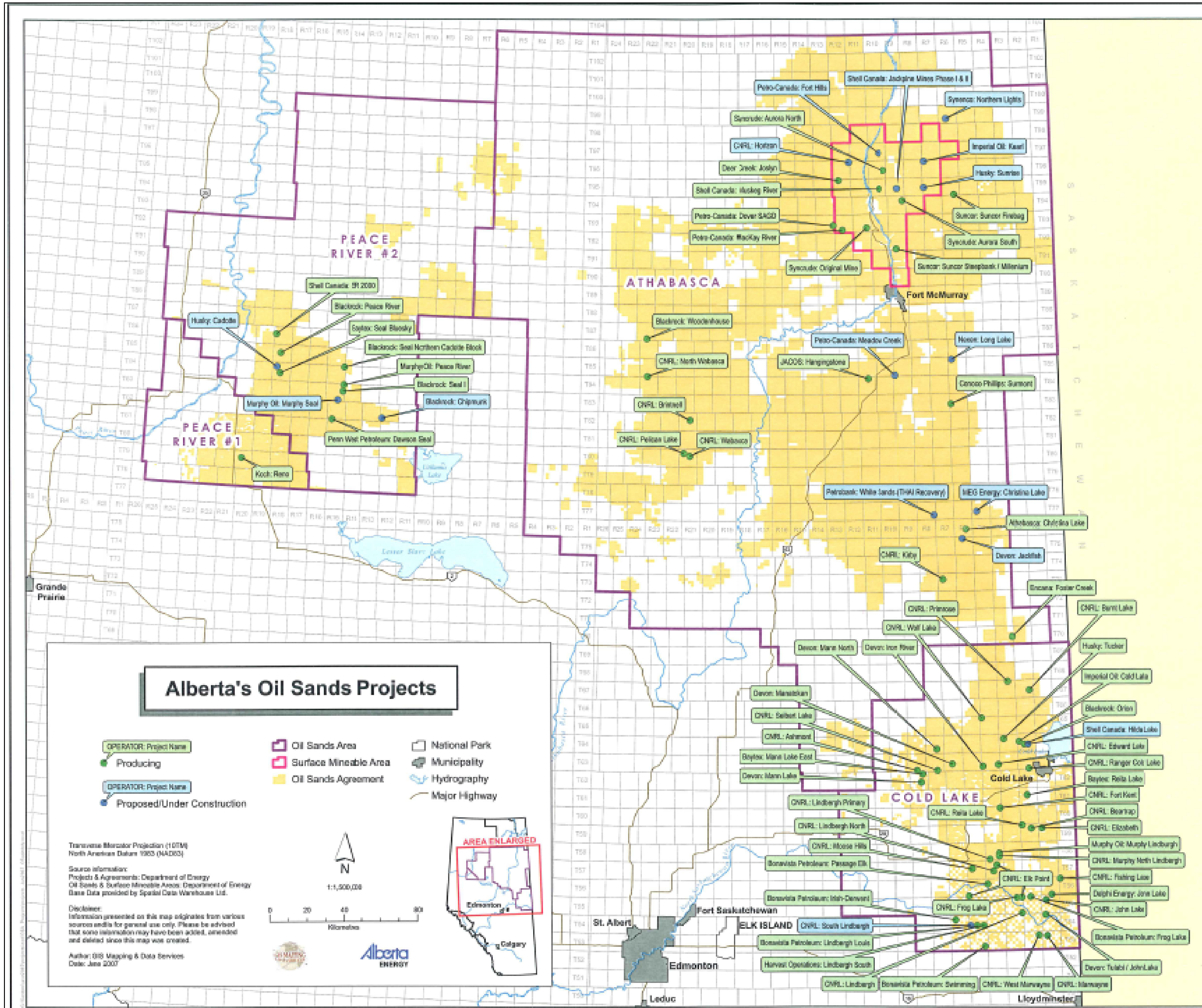


Figure 8, Alberta Oil Sands Resource Distribution



Athabasca Oil Sands Area	Stage of Development
Mining Projects	
Fort Hills	Proposed
Northern Lights	Proposed
Mining Projects	
Horizon	Under Construction
Jackpine Mines Phase I & II	Under Construction
Kearl	Proposed
Muskeg River (offsite upgrader)	Producing
Suncor Steepbank/Millenium (onsite upgrader)	Producing
Syncrude (Original Mine, Aurora North, Aurora South)	Producing
SAGD Projects	
Christina Lake - EnCana	Producing
Christina Lake - MEG Energy	Proposed
Dover SAGD	Producing
Foster Creek	Producing
Hangingstone	Pilot Plant
Jackfish	Proposed
Joslyn	Producing
Kirby	Suspended
Long Lake (onsite upgrader)	Under Construction
MacKay River	Producing
Meadow Creek	Proposed
Suncor Firebag	Producing
Sunrise (offsite upgrader)	Proposed
Surmont	Producing
White Sands (THAI Recovery)	Proposed
Primary Projects	
Brintnell	Producing
North Wabasca	Producing
Pelican Lake	Producing
Wabasca	Producing
Woodenhouse	Producing
Cold Lake Oil Sands Area	
CSS Projects	
Cold Lake	Producing
Elk Point Crown Agreement	Producing
Lindbergh Crown Agreement	Producing
Murphy Lindburgh Crown Agreement	Producing
Primrose	Producing
Wolf Lake	Producing
SAGD Projects	
Burnt Lake	Producing
Hilda Lake	Proposed
Orion	Experimental
Tucker	Producing
Primary Projects	
Ashmont	Producing
Beartrap	Producing
Edward Lake	Producing
Elizabeth	Producing
Elk Point	Producing
Fishing Lake	Producing
Fort Kent	Producing
Frog Lake	Producing
Irish-Derwent	Producing
Iron River	Producing
John Lake - Delphi Energy	Producing
John Lake - CNRL	Suspended
Lindbergh Louis	Producing
Lindbergh North	Producing
Lindbergh Primary	Producing
Lindbergh South	Producing
Manatokan	Producing
Mann Lake	Producing
Mann Lake East	Producing
Marwayne	Producing
Moose Hills	Producing
Murphy North Lindbergh	Producing
Passage Elk	Producing
Ranger Cold Lake	Producing
Reita Lake	Producing
Seibert Lake	Producing
South Lindbergh	Proposed
Swimming	Producing
Tulabi/John Lake	Producing
West Marwayne	Producing
Peace River Oil Sands Area	
Primary Projects	
Cadotte	Proposed
Chipmunk	Proposed
Dawson Seal	Producing
Murphy Seal	Proposed
Peace River	Producing
Reno	Producing
Seal Bluesky	Producing
Seal I	Producing
Seal Northern Cadotte Block	Producing
CSS Projects	
Peace River	Producing
SR 2000	Producing

Figure 9, Locations of Current & Planned Oils Sands Projects

9 Electricity Demand in Alberta

9.1 Grid Capacity & Projected Growth

According to Statistics Canada, Alberta's (AB) installed electrical capacity was 11,351 MW at the end of 2005. Since then, 250 MWe of wind capacity, 240 MWe of natural gas cogeneration, and 10 MWe of gas-fired capacity has been added. The Alberta Department of Energy states that the record peak load in Alberta set on November 28, 2006, was 9,661 MWe.

The Provinces of British Columbia (BC) and Alberta have one (1) 500 kV interconnection between Langdon AB and Cranbrook BC, and two (2) 138 kV interconnections linking the Coleman and Pocaterra substations in Alberta to the Natal substation in BC. These three (3) interconnections cross the BC-Alberta borders in the south. In total, the nominal BC to AB capacity is 1200 MW, although system limitations are constraining this capacity to 800 MW. Likewise, the nominal AB to BC capacity is 1000 MW, which is constrained by Alberta's grid system limitations to 780 MW. However, during some periods the transmission of power from Alberta to BC is not possible. BC-Alberta transmission constraints could be alleviated by a number of transmission upgrades in Alberta. Figure 10 shows the electricity trade between Alberta and the adjoining provinces and US states. However, it does not accurately show the locations of the transmission facilities. There are no BC to AB transmission links in the Peace River area of northern BC and AB.

The Alberta Electric System Operator (AESO) predicts that by 2016-17, the peak electrical load in Alberta will be 13,170 MW in a normal scenario, and 14,200 MW in a 'high-industrial' scenario. Hence, the peak load is predicted to increase by approximately 4000 MWe between now and 2018, for an increase of 400 MWe per year. For the five (5) year period following 2018, SLN has assumed that electricity demand will increase by 500 MWe per year.

Alberta imports electricity from the US at times through its BC transmission line interconnections. The availability of BC and/or US electricity in Alberta in future is dependant upon BC's electricity market balance, and the electricity market balance of the entire Pacific Northwest region.

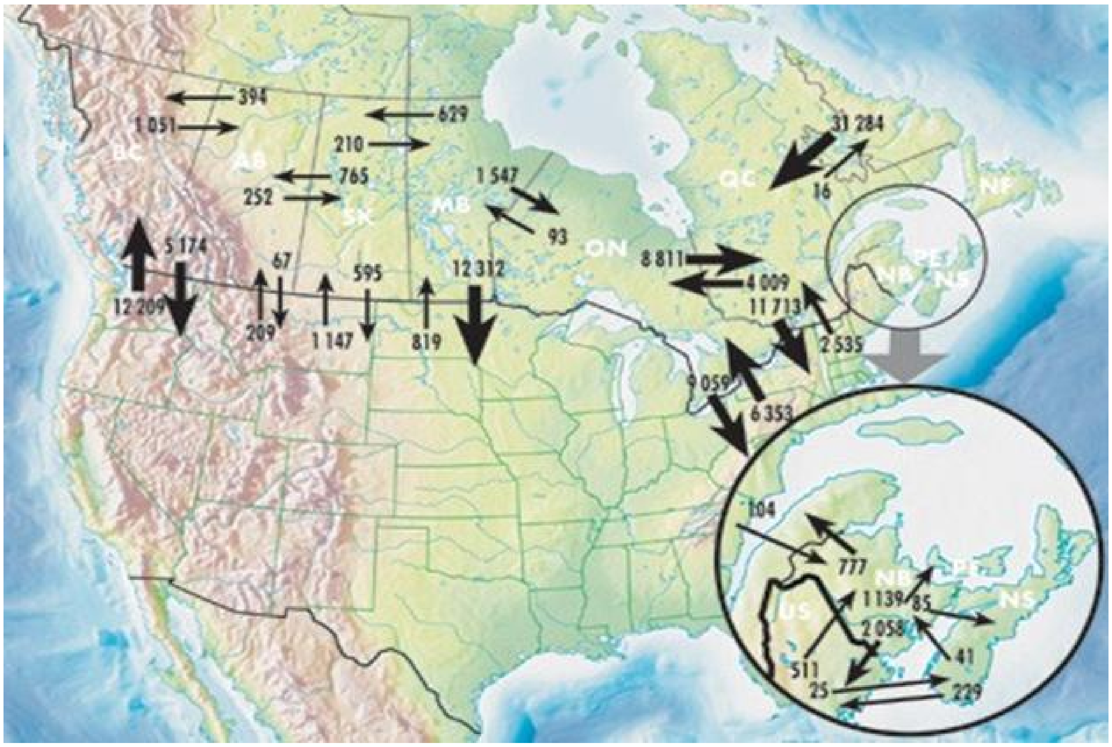


Figure 10, Electricity Trade Between Provinces & States

9.2 Nuclear Power Plant Compatibility with the Alberta Grid

Determining the capability of Alberta's electricity grid to support nuclear power plants of various sizes will require a grid assessment study to address the distribution of electricity, the magnitude and distribution of electricity demand, electricity generation options (plant type, size, and location), and grid stability. However, a rule that is widely used states that the capacity of any generation facility should not exceed 10% of the grid generation capacity. Lower limits are frequently placed on large, distributed and low density electrical grids. Based on the above 10% rule, the Alberta electrical grid could presently accept electrical power from NPPs in the 1000 MW and 1500 MW classes by approximately 2018.

A time frame of approximately 11 years or more is required to place a nuclear power plant in service (see Figure 25 and Figure 26). Hence, the first potential in-service date for a nuclear power plant would be approximately 2020. If an average increase in electricity demand of 500 MW per year is assumed after 2017, one (1) 1000 MWe class nuclear power plant entering service every two (2) years, or one (1) 1500 MW class nuclear power plant entering service every three (3) years would meet the electricity demand. The deployment of large, nuclear power generating plants will require substantial upgrades of the Alberta electrical grid.

If nuclear power plants are constructed in areas of steam demand by the Oil Sands operators, a portion of the output from the nuclear plants can be utilized by the operators as steam. A 20% portion of the thermal output from a water cooled nuclear power plant would provide between 400 MWth and 900 MWth of steam.

Although electricity can be carried by transmission lines over long distances, the transmission costs (i.e., capital, transmission system maintenance, and line losses) can be substantial and impact on the economic feasibility of transmitting electricity from the Oil Sands regions to load centers in southern Alberta.

10 Steam Compressors

10.1 Overview

The steam pressures available from NPPs utilizing water cooled reactors falls short of those required for in-situ bitumen extraction scenarios, and are inadequate for steam distribution over significant distances. For this reason, the use of steam compressors was evaluated.

Large capacity steam compressors are not commercially available. Several compressor technologies are potentially available, including turbine, screw, piston, and Roots compressors. However, turbine compressors were determined as the only compressor technology that is suitable for capacities in the range required by the Oil Sands in-situ applications. For example, if a steam turbine is used to power the steam compressor, approximately 75% of the steam produced by a NPP at 6 MPa can be compressed to 16 MPa.

Large steam compressors have not been constructed to-date. This is probably due to the absence of demand for these devices, so there is no experience base. However, the current evaluation indicates that steam turbine compressors are feasible, utilizing the current technology. The major steam turbine manufacturers (other than Alsthom), which are the logical suppliers of large steam turbine compressors, have not expressed any interest in developing the technology. However, their attitudes may change if presented with a real commercial opportunity. Both Alsthom and ManTurbo have submitted a conceptual design for a turbine steam compressor, and provided a budgetary cost estimate (see Appendix T).

Deployment of turbine steam compressors will require a design and development program, including the testing of a demonstration turbine steam compressor. This development program can be accommodated within the research and development period identified in the implementation schedule for a nuclear power plant, as shown in Figure 25 and Figure 26.

In the reference arrangement, a portion of the steam produced by the nuclear steam plant passes through a steam turbine to a vacuum condenser. This steam turbine is utilized to drive a turbine steam compressor that compresses the required steam flow (see Figure 11). In Figure 11, the ratio of compressed steam flow to total steam flow from the nuclear steam plant is plotted against the final compressed steam pressure for four (4) different nuclear steam plant delivery steam pressures, covering the range of between 4 MPa and 7 MPa. For example, if the nuclear steam plant steam pressure is 5 MPa, approximately 80% of the steam can be compressed to 13 MPa, assuming 95% steam turbine compressor efficiency.

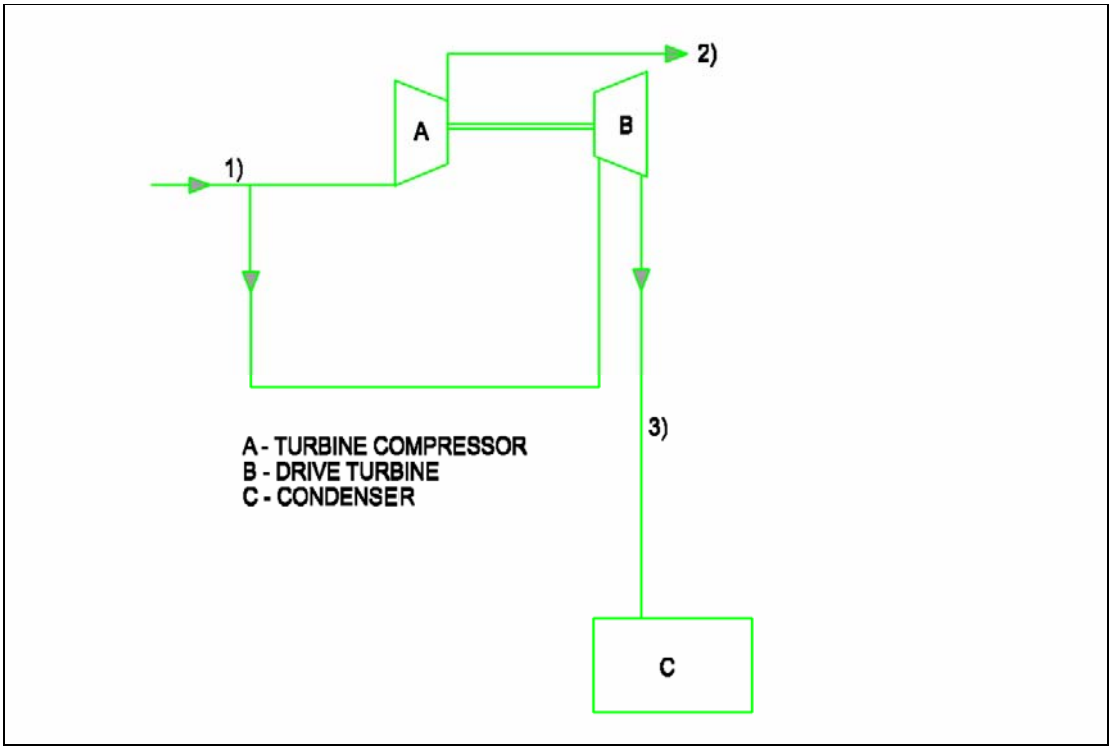


Figure 11, Steam Compressor & Drive Turbine Configuration

Note: 1) Steam from NSP, 2) Steam to in-situ application, 3) Steam to condenser

Table 6 provides steam cycle information based on a NPP steam supply of 100 MWth for the AP1000 (Case 1) and the CANDU 6E (Case 2). General compressor performance information is provided in Figure 12.

Table 6, Turbine Steam Compressor Steam Cycle Information

Details	MWth	Flow (kg/sec.)	Pressure (MPa)	Temp °C	Quality %
Case 1 – AP1000					
NSS steam conditions	100	49	5.8	273.2	100
Compressor Outlet Conditions	85.43	41.86	12.0	373.34	Superheated
Drive Turbine Outlet Conditions	14.57	7.14	0.005	32.88	70.63
Case 2 – CANDU6E					
NSS steam conditions	100	48.69	4.6	258.8	100
Compressor Outlet Conditions*	80.6	39.25	12.0	391.65	Superheated
Drive Turbine Outlet Conditions**	19.4	9.44	0.005	32.88	71.89

Note (for above table) *assumed steam-compressor isentropic efficiency of 95%, resulting in the Compressor Outlet Enthalpy 2946.69 kJ/kg for Case 1, and 3017.67 kJ/kg for Case 2.

**assumed steam-turbine isentropic efficiency of 95%, and assumed condenser pressure of 5 kPa(a) or 0.005 MPa(a) (saturated temp. 32.88°C).

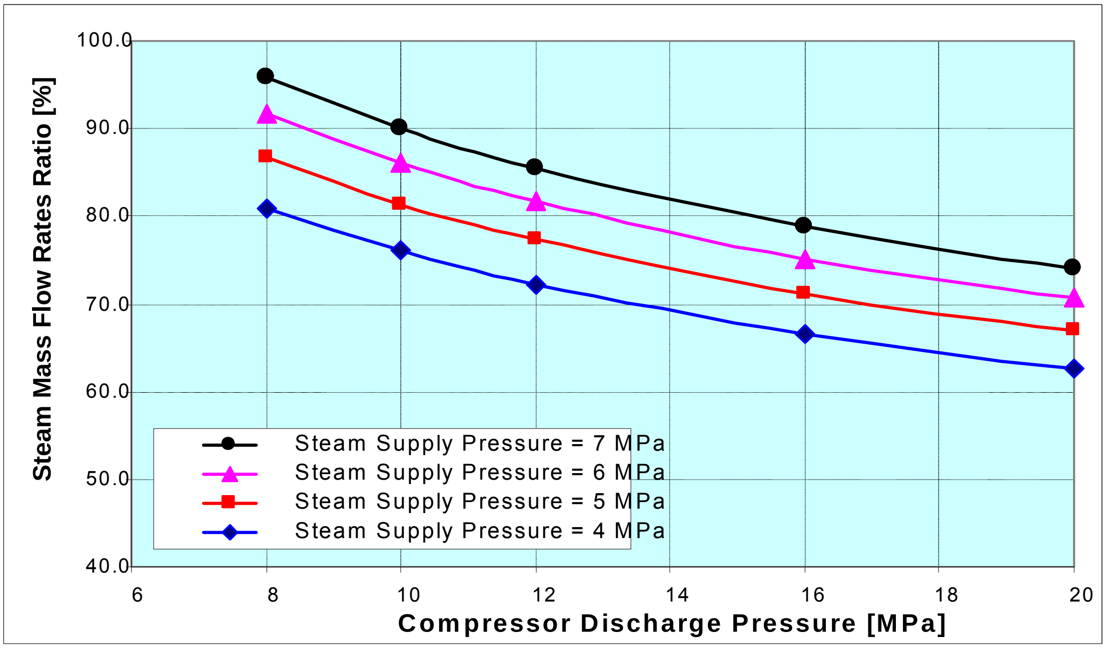


Figure 12, Steam Compression as a Function of NPP Delivery Pressure

10.2 Application of Steam Compressors

The anticipated performance curves for turbine steam compressors indicate that turbine steam compressors are essentially “single point” performance machines. Specifically, if the reference operating point rotational speed is reduced, both the outlet steam flow and steam pressure are reduced.

A cursory review of potential applications suggests that a dedicated steam compressor should be provided for each phase of each Oil Sands application requiring steam pressures higher than those available from the NPP. Operational flexibility can be provided by utilizing balance headers that interconnect the steam compressor outputs. This review further indicates that operation may be optimized by providing dedicated drive turbines for each steam compressor.

The drive turbine configuration shown in Figure 13 provides an economic option. The drive turbine consists of one (1) single flow, combined High Pressure (HP) and Low Pressure (LP) cylinder with internal moisture separation, with an operating speed of 3600 rpm. Both the HP and LP sections are of disc and diaphragm construction with low reaction blading. Significant features of this turbine arrangement are the location of the power shaft at the HP end of the assembly, and the discharge of steam directly into the condenser (see Figure 14). A major advantage of the turbine-generator configuration and size is that Turbine-Generator units are shipped as factory commissioned modules, which greatly reduces their installation and commissioning time. A further advantage is that excavation to accommodate the condenser below the turbine assembly, which is common to most generating facilities, is avoided.

The arrangement of the drive Turbine-Generator assembly is illustrated in Figure 15.

The drive turbine configurations shown in Figure 13 and Figure 15 are extracted from a proprietary proposal prepared in 1994 that covered a Turbine-Generator set operating with saturated inlet steam conditions of 4.3 MPa. The input to the turbine is 328 MWth, and the generator output is 111 MWe at the generator terminals. Information provided in the proposal indicates that this configuration is viable through the 500 to 600 MWth input range.

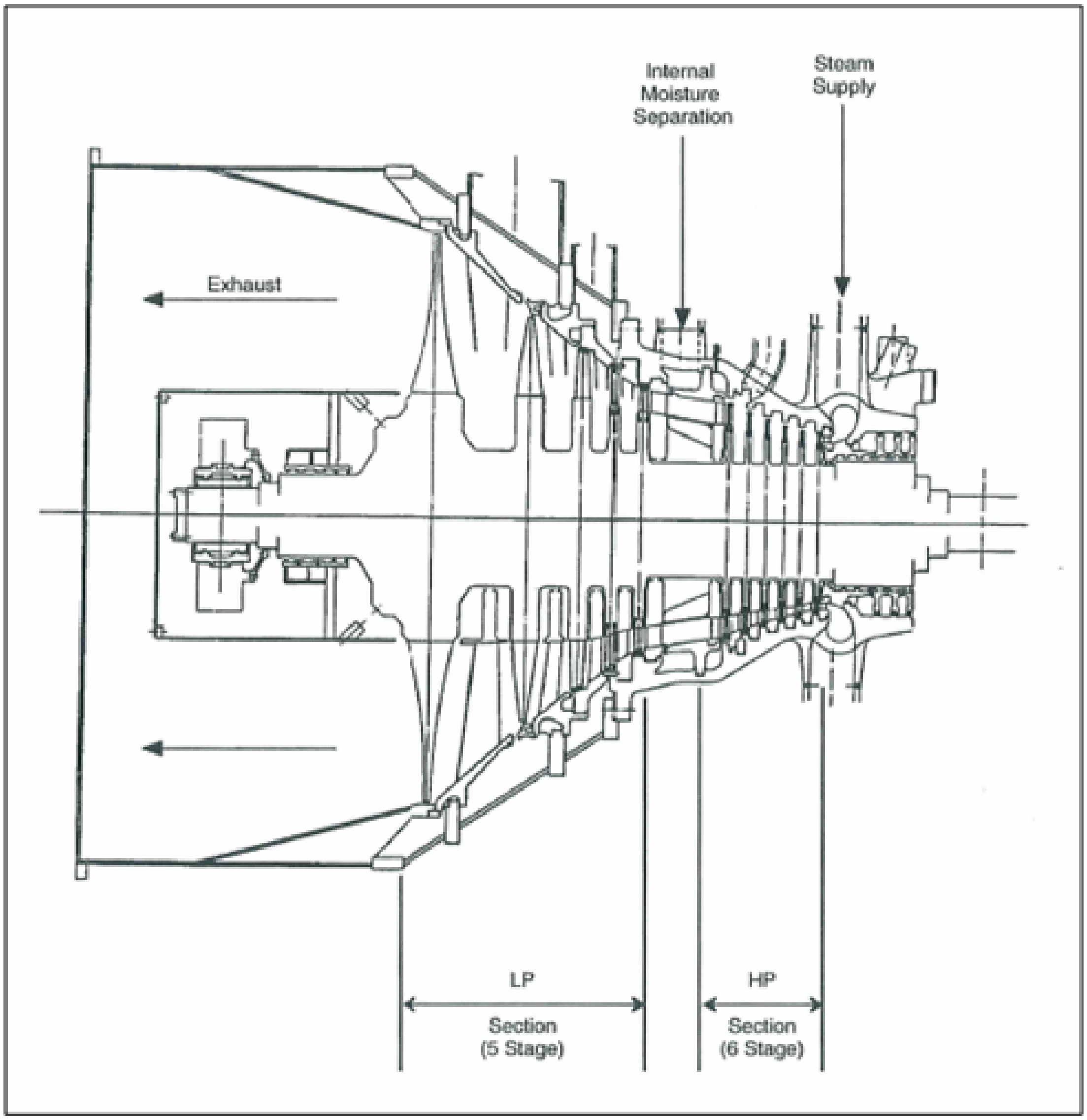


Figure 13, Potential Drive Turbine Configuration

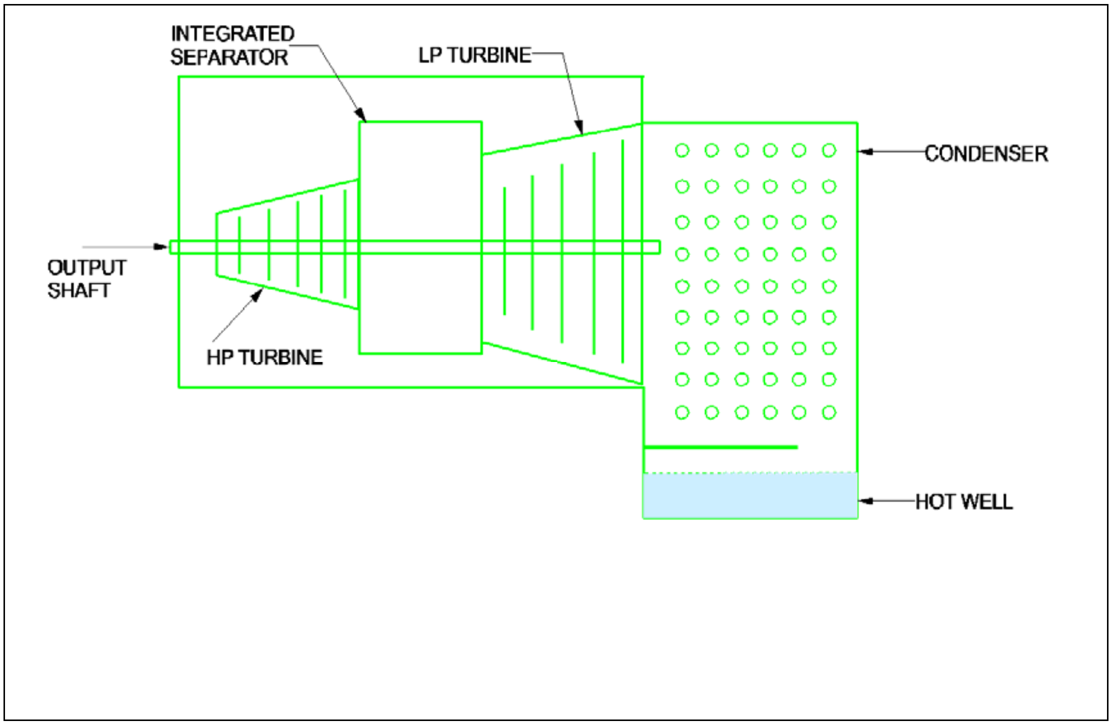


Figure 14, Drive Turbine & Condenser Configuration

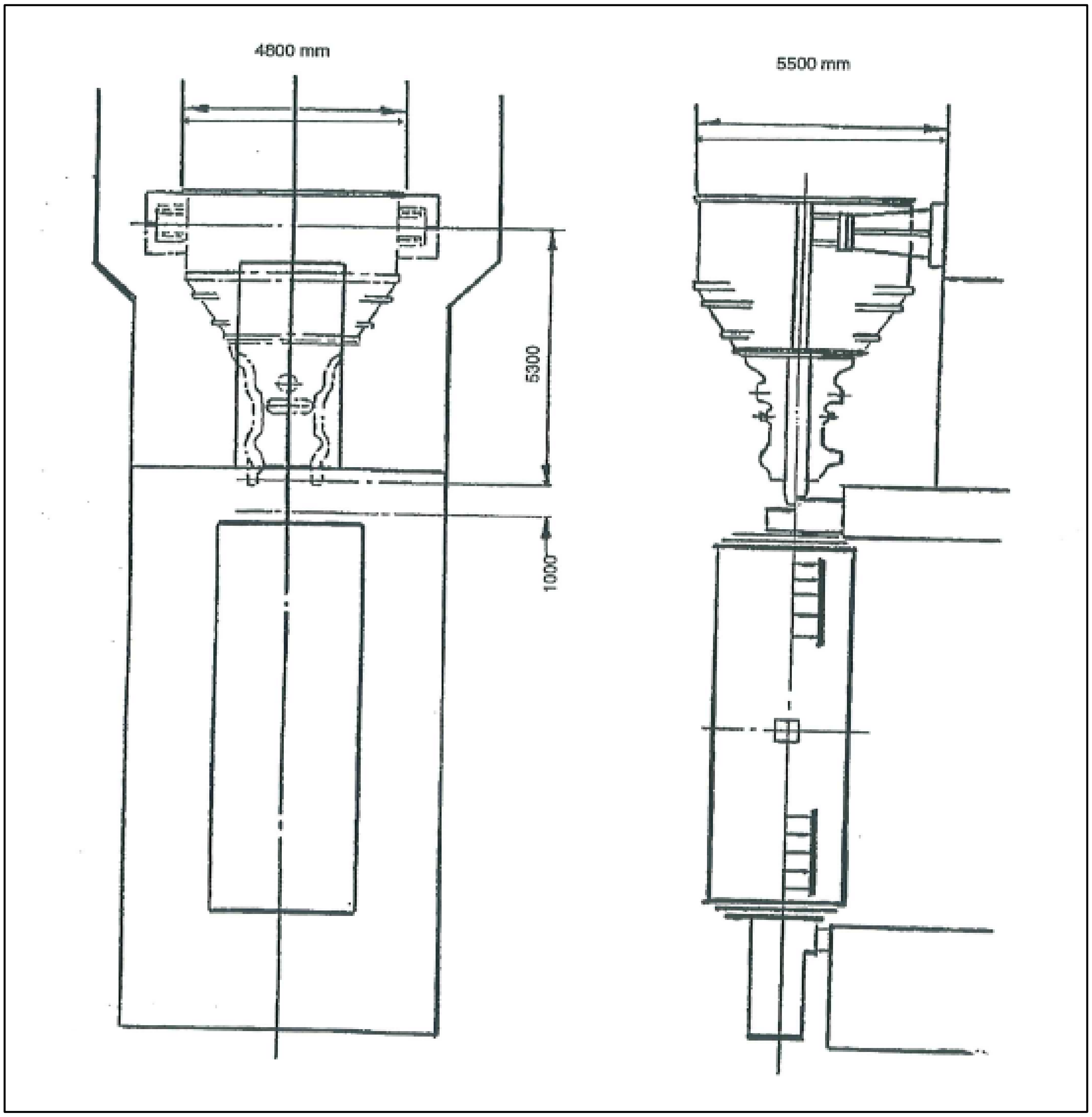


Figure 15, Drive Turbine-Generator Arrangement

A potential configuration applicable to the AP1000 that provides cogeneration capability is shown in Figure 16. In this configuration, the AP1000 output (3060 MWth) is distributed equally to six (6) identical drive turbines (510 MWth capacity each). In Figure 16, two drive turbines are connected to generators, while the remaining four (4) drive turbines are connected to steam compressors. However, the ratio of generators to compressors can be varied to suit the application. Each generator delivers approximately 168 MWe for a total electrical output of 236 MWe, which results in approximately 200 MWe being available for Oil Sands applications after allowance for Station loads.

Each of the steam compressors provide approximately 408 MWth of steam at 12 MPa, which is consistent with the requirements specified for each phase of the reference in-situ application.

The configuration presented in Figure 16 gives priority to standardization, with all drive turbines, generators and steam compressors being identical.

In the case of the CANDU 6E, the output (2080 MWth) is distributed equally to four (4) identical drive turbines (520 MWth capacity each). One (1) drive turbine is connected to the generators, while the remaining three (3) are connected to steam compressors. However, the ratio of generators to compressors can be varied to suit the application. The generator delivers approximately 176 MWe which provides approximately 122 MWe for Oil Sands applications, with allowance for Station loads. Each steam compressor delivers 419 MWth of steam at 12 MPa.

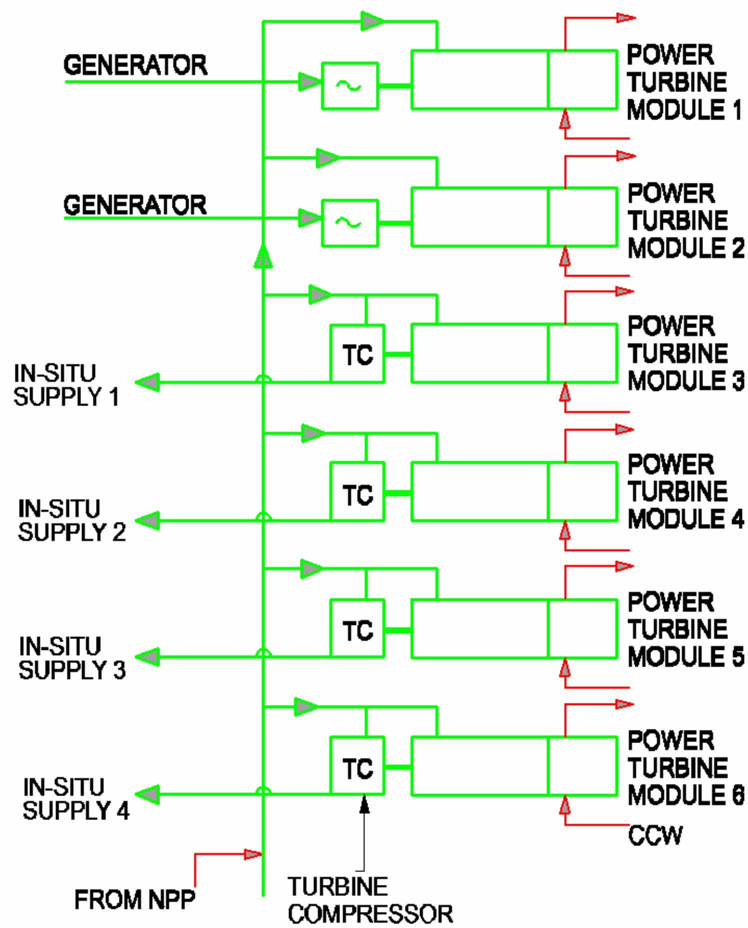


Figure 16, Potential AP1000 Configuration for Cogeneration Capability

10.3 Economics of Steam Compressor Systems

The cost of the turbine generator assembly as defined in the above section in 1997 dollars was $47M, including all auxiliaries and commissioning, which is approximately $59M in 2007 dollars. The cost for a unit in the 500 MWth input range is projected to be 24% greater, or approximately $74M. The turbine generally represents about 20% of the Turbine-Generator unit cost. Hence, the cost of the turbine drive assembly is expected to be in the range of $60M (2007 dollars). SLN estimates the cost of each steam compressor at $21M. Due to variations in the exchange rates and other variables, the above estimates are indicative only.

A summary of projected costs for the AP1000 configuration presented in Figure 16 is presented in Table 7.

Table 7, Cost of Turbine Compressor & Turbine Generator Assemblies (2007 Dollars)

Item	Unit Cost	Number of Units	Total Cost
Turbine Generator	$90M	2	$180M
Compressor Drive Turbines	$60 M	4	$240M
Turbine Steam Compressors	$21M	4	$84M
Total Cost of Equipment			$504M

By comparison, the cost of the Turbine-Generator unit (including auxiliaries) for the AP1000 is estimated at $487M (2007 dollars). The equipment cost for the cogeneration configuration illustrated in Figure 16 for the AP1000 is therefore approximately $17M greater than for the Turbine-Generator and auxiliaries for the reference electricity generating plant. Within the accuracy of the estimates, the costs should be considered as the same. However, the installation of the commissioned modules and ease of shipping of the cogeneration equipment will serve to reduce this cost differential. In addition, the thermal output of the AP1000 that is available to Oil Sands applications and electricity production is reduced by approximately 10%.

In summary, the cogeneration configuration illustrated in Figure 16 appears to provide a flexible and economically viable method for adopting water cooled reactors to in-situ applications, and for providing the capability of steam distribution for mining and integrated mining applications.

11 Reboilers

In Oil Sands applications, reboilers utilize heat to convert the recovered water from Oil Sands operations (after processing) into steam, which is then utilized for Oil Sands operations.

Reboilers located at the NPP site are required for BWRs, and may prove to be advantageous for other NPP applications.

Reboilers utilizing the steam supplied by NPPs are feasible when the minimum temperature differences between the saturation temperature of the NSP steam supply and the Oil Sands steam supply are in the range of 10 ^{o}C. However, the reboiler cost is reduced by increased temperature differentials. The available temperature differentials as a function of NSP steam supply pressure and the 8.5 MPa Oil Sands application steam pressure are given in Figure 17.

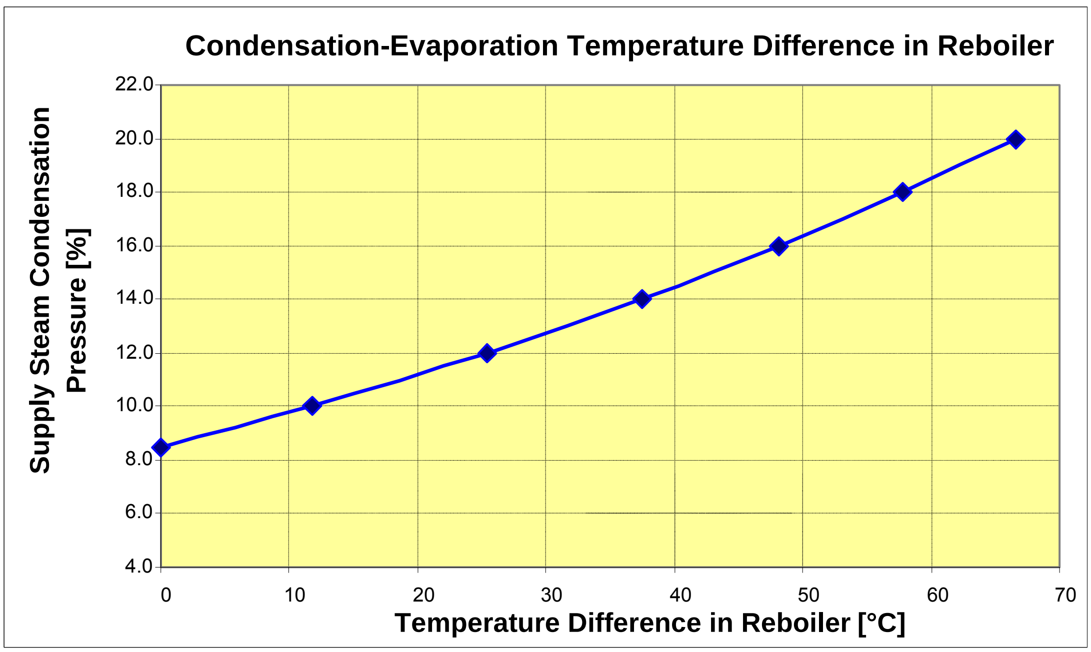


Figure 17, Reboiler Temperature Differentials as a Function of Supply Pressure

Electrically powered reboilers are technically feasible. These would allow the electricity generated by NPPs to be transmitted to end-user locations and utilized for generating steam for Oil Sands applications. However, the commercially available electric boilers are of small capacity and low pressure relative to the steam demands of the in-situ Oil Sands applications. A development program would therefore be required to demonstrate the performance of electric reboilers that meet the required Oil Sands steam conditions. In addition, approximately 65% of a NPP water cooled reactor’s thermal output is rejected to the environment during the production of electricity.

12 Hydrogen Production

Upgrading processes that are currently employed in the Oil Sands region utilize approximately 2000 Standard Cubic Feet (SCF) or approximately 4.83 kg of hydrogen per barrel of syncrude produced.

The production of hydrogen by electrolysis whereby electricity is used to split water atoms into their atomic components of hydrogen and oxygen consumes approximately 50 kWh of electricity to produce one kilogram of hydrogen. Hence, approximately 240 kWh of electricity is required for each barrel of syncrude that is produced utilizing the hydrogen produced by electrolysis. High temperature electrolysis has the potential to increase hydrogen production efficiency.

Electrolysis technologies are well established. The electricity generated by any of the NPPs considered can be utilized for hydrogen production by employing the electrolysis technologies. Studies are required that will consider the power plant locations, the electrolysis plant locations, and the hydrogen and electrical distribution systems in order to determine an optimum system configuration. Licencing requirements for nuclear power plants will preclude the location of hydrogen production facilities close to the nuclear plants. Heat provided by the nuclear plants considered is well suited to the high temperature electrolysis processes. The temperature capability of the HTGRs has the potential of further increasing hydrogen production efficiency through electrolysis.

Hydrogen is currently produced in the Oil Sands region, predominately by methane reforming. Although the cost of hydrogen production by methane reforming is estimated be approximately 30% less than by low temperature electrolysis, the process results in large CO_2 emissions. Heat provided by a HTGR could be used to supply energy to the methane reforming process, thereby reducing CO_2 emissions.

Thermochemical water splitting has been investigated sporadically over the past 25 years and is receiving renewed interest, especially in China, Korea and Japan due to the high potential efficiency of hydrogen generation. Thermochemical water splitting technology requires temperatures in the range of 800°C. HTGRs, due to their high temperature capability, are ideally suited as an energy source for the efficient production of hydrogen by water-splitting using the Sulphur-Iodine thermochemical process shown in Figure 18. Use of the nuclear energy generated by HTGRs for thermochemical water splitting processes to produce hydrogen would not result in CO_2 emissions.

The Korean Atomic Energy Research Institute (KAERI) undertook a US$ 1B R&D and demonstration program in 2005 aimed at producing commercial hydrogen using HTGR heat by 2020 (ref. [48]). KAERI is closely linked to hydrogen production with the Institute of Nuclear & New Energy Technology (INET) at Tsinghua University in China, covering research utilizing China's HTR-10 pebble bed research reactor. In 2005, KAERI established a South Korea / US Nuclear Hydrogen Joint Development Center in cooperation with General Atomics.

KAERI, as part of their hydrogen production program, submitted a Very High Temperature Reactor (VHTR) design to the Generation IV International Forum with a view to hydrogen production in 2005 (ref. [48]). The VHTR proposed by KAERI consists of 300 MWth modules. Each module will be capable of producing 30,000 tonnes of hydrogen per year. KAERI expects the conceptual design of their VHTR to be completed in late 2008, with the detailed engineering design completed in 2014, construction starting in 2016, and operation in 2020.

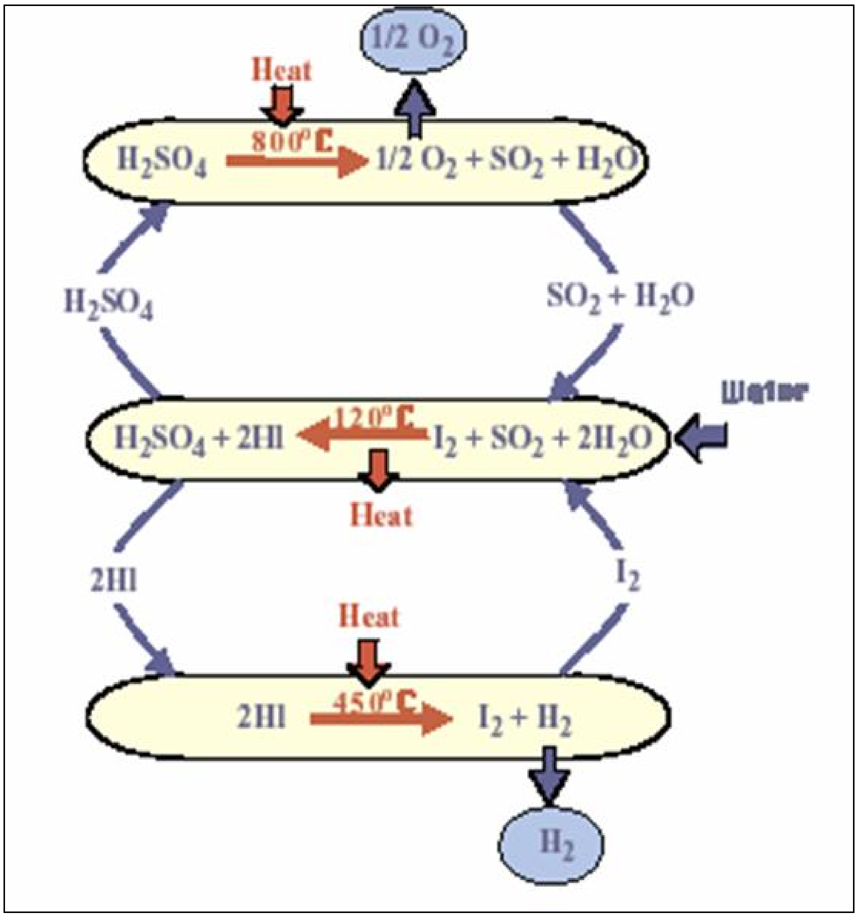


Figure 18, Sulphur-Iodine Thermochemical Water-Splitting Cycle

13 Nuclear Contribution to Coal Liquefaction & Coal Gasification

The liquefaction and gasification of coal can be utilized to reduce the environmental emissions relative to the direct combustion of coal, and to facilitate distribution of the liquid products and gas generated through conventional (and often existing) pipeline distribution systems. An overview of Direct Coal Liquefaction (DCL), Indirect Coal Liquefaction (ICL) and coal gasification technologies is provided in Appendix M. These technologies are receiving increased attention world-wide, and are a focus of commercialization efforts in China.

The established coal gasification technologies require large amounts of heat energy. The use of nuclear power plants to provide this energy would substantially reduce the environmental impact of the coal gasification facilities. The required temperatures are within the capability of the HTGR technologies.

As outlined in Appendix M, the substitution of nuclear power for coal derived power to the DCL, ICL, and coal gasification processes can reduce the amount of coal consumed by up to 40%, while substantially simplifying the processes.

A presentation by General Atomics with additional information is also included in Appendix M.

14 Nuclear Steam Plant Assessment

14.1 Overview

The following provides a brief overview and evaluation of the various nuclear power plants being considered in this study.

ABWR: The capacity of the ABWR is approximately 4000 MWth, which exceeds the specified Oil Sands project scenario requirements specified by PTAC by more than 100%, and the mining scenario requirements by a factor of approximately five (5). For a summary of NPP capacities relative to requirements, see Table 8. The steam pressure provided by the Nuclear Steam Plant (NSP) is in the 7.7 MPa range. Since a reboiler is required, the available steam pressure at the reboiler outlet will be in the range of 6 MPa, which falls short of the in-situ extraction requirements, but is sufficient for the mining and integrated mining applications. The ABWR is licenced and operating in Japan and Taiwan, and has received a Standard Product Licence in the US. BWR licencing requirements and procedures are well established in more than a dozen countries, including the United States. The ABWR should be licencable in Canada. However, the licencing process could be time consuming due to the lack of CNSC experience with the licencing of this technology.

ACR-1000: The capacity of the ACR-1000 is approximately 3200 MWth, which exceeds the Oil Sands project requirements specified by PTAC for the in-situ and integrated mining applications by approximately 50%, and the requirements for the mining scenario by approximately a factor of four (4). For a summary of NPP capacities relative to requirements, see Table 8. The steam pressure, which is 5.9 MPa, falls short of the in-situ extraction requirements, but is sufficient for the mining and integrated mining applications. The ACR-1000 is a new and unproven design, and has not been committed for construction. A substantial effort is therefore required to establish the performance and licencability of the ACR-1000 NPP. The advantages claimed for the ACR-1000 relative to a conventional CANDU of similar size are a near zero void reactivity coefficient, and reduced capital cost that is largely due to reduced heavy water requirements. A site licence application to the CNSC has been submitted by Alberta Energy for the construction of two (2) ACR-1000 units in the Peace River Valley of Alberta. Licencing the ACR-1000 could be time consuming due to the novel features of the design (ref. [11]) and the lack of prior licencing experience. The first ACR-1000 constructed will be a ‘first-of-a-kind’ (FOAK) plant. Schedule delays and initial operating problems that are typical of FOAK plants should be anticipated.

AP1000: The capacity of the AP1000 is approximately 3000 MWth exceeds the Oil Sands project requirements specified by PTAC for the in-situ and integrated mining applications by approximately 50%, and the requirements for the mining scenario by approximately a factor of four (4). For a summary of NPP capacities relative to requirements, see Table 8. The steam pressure, which is 5.8 MPa, falls short of the in-situ extraction requirements, but is sufficient for the mining and integrated mining applications. The AP1000 is licenced for construction in China, and has received a Standard Product Licence in the US, and approval by the European Union. PWR licencing requirements and procedures are well established in more than a dozen countries, including the United States. The AP1000 makes extensive use of proven systems and components in the nuclear and power producing systems, while introducing passive containment and core cooling safety systems. The AP1000 is highly modularized, with the modules being shippable by road or rail, which is an advantage for isolated area applications. The AP1000 should be licencable in Canada. However, the licencing process could be time consuming since the CNSC has not licenced a NPP that utilizes PWR technology. The AP1000 is in the early stages of construction in China (four units) and will have operating experience prior to a start of construction date in Canada.

CANDU 6E: The CANDU 6E has the smallest capacity of the NPPs utilizing water cooled reactors. However, its output of 2080 MWth exceeds the specified Oil Sands in-situ and integrated mining requirements by approximately 20%, and the mining scenario requirements by a factor of more than two (2). For a summary of NPP capacities relative to requirements, see Table 8. The CANDU 6E is based on the proven CANDU 6, which has excellent operating experience spanning more than 25 years. CANDU 6E design changes relative to the latest CANDU 6 include the adoption of a steel-lined, full pressure containment structure, increased capability of safety support systems, and increased separation of safety and production systems. The CANDU 6E has a high degree of provenness in the nuclear and power production systems. The steam pressure at 4.6 MPa is the lowest of the NPPs utilizing water cooled reactors considered, and falls far short of the in-situ extraction requirements, but is sufficient for the mining and integrated mining applications. Licencing of the CANDU 6E should be relatively easy due to CNSC familiarity with the CANDU 6 design, and the long licencing history of the CANDU 6.

EPR: The capacity of the EPR at approximately 4500 MWth exceeds the in-situ and integrated mining scenario requirements as specified by PTAC by a factor of approximately three (3), and the mining scenario requirements by a factor of more than five (5). For a summary of NPP capacities relative to requirements, see Table 8. The steam pressure which is in the 6 MPa range is also insufficient for in-situ applications, but is sufficient for the mining and integrated mining applications. The EPR is licenced for construction in Finland and France. US NRC review of the US-EPR began in November, 2007, and two (2) EPR units were ordered by China in November, 2007. The EPR will have operating experience prior to a start of construction date in Canada. PWR licencing requirements and procedures are well established in more than a dozen countries, including the United States. The EPR should be licencable in Canada. However, the licencing process could be time consuming since the CNSC has not licenced a NPP that utilizes PWR technology.

ESBWR: The capacity of the ESBWR at approximately 4500 MWth exceeds the specified in-situ and integrated mining scenario requirements as specified by PTAC by a factor of approximately three (3), and the mining scenario requirements by a factor of more than five (5). For a summary of NPP capacities relative to requirements, see Table 8. The steam pressure of 7.7 MPa at the reactor provides steam in the 6 MPa range at the reboiler outlet, which falls short of the in-situ extraction requirements, but is sufficient for the mining and integrated mining applications. The ESBWR incorporates many passive features, including passive containment, fuel cooling, and the elimination of recirculation pumps. These features will significantly reduce both the capital cost and operating cost of the ESBWR relative to the ABWR. The ESBWR is in the process of obtaining a Standard Product Licence in the US. BWR licencing requirements and procedures are well established in more than a dozen countries, including the United States. The ESBWR should be licencable in Canada. However, the licencing process could be time consuming since the CNSC has not licenced a NPP that utilizes BWR technology. The first ESBWR will be a 'first-of-a-kind' (FOAK) plant. Schedule delays and initial operating problems that are typical of FOAK plants should be anticipated. However, the first ABWRs entered service on schedule and have performed well.

GA-HTGR: The GA-HTGR has a capacity of 600 MWth, which is compatible with the specified mining energy requirements, and less than the energy requirements for integrated mining and in-situ extraction by a factor of almost three (3). For a summary of NPP capacities relative to requirements, see Table 8.The available steam pressures, which are in the 17 MPa range, are sufficient for all Oil Sands applications. The steam pressure and superheat provided by the GA-HTGR facilitates steam distribution over significant geographic areas, and provides a range of cogeneration options. Although GA has the capability and experience to complete the GA-HTGR design and have it market-ready within a period of approximately six (6) years, the completed GA-HTGR design does not currently exist. The first GA-HTGR unit will be a 'first-of-a-kind' (FOAK) and can be expected to experience a number of construction delays and technical problems, which has been the case with many FOAK units (e.g., the EPR under construction in Finland). HTGRs have been licenced in Germany (pebble bed) and the US (prismatic core). A construction licence has been issued for a commercial pebble bed HTGR in China, and the PBMR is currently undergoing regulatory review in South Africa. The GA-HTGR should be licencable in Canada. However, the licencing process could be time consuming since the CNSC has not licenced a NPP that utilizes HTGR technology, and because of the relatively weak international experience base. A summary of a study of GA-HTGR applicability to the Oil Sands applications is provided in Appendix N. The GA-HTGR has the potential of serving future thermochemical water splitting hydrogen production, and coal liquefaction and gasification applications.

PBMR: The PBMR that is currently in the design process has a capacity in the 375 MWth range, and is dedicated for electricity production utilizing a direct cycle. Although the PBMR organization has proposed a 500 MWth configured PBMR for steam production, the 375 MWth version demonstration plant being designed is the reference PBMR used for this report's evaluations. The design of a new reactor of higher capacity, including the associated steam production systems, and the establishment of new licencing criteria will delay the availability of the 500 MWth version to beyond the time frame considered in this study.

The capacity of the 375 MWth PBMR is approximately half of what is required for the mining scenario as defined by PTAC a factor of four (4) or more less than the energy requirements specified for integrated mining and in-situ extraction. The available steam pressure, which is in the 11 MPa to 17 MPa range, is sufficient for all Oil Sands applications. The steam pressure and superheat provided by the PBMR facilitates steam distribution over significant geographic areas, and provides a range of cogeneration options. The PBMR is compatible with the defined Oil Sands project scenario requirements in terms of steam pressure and capacity.

PBMR has published material and made presentations for a 500 MWth PBMR design that produces steam at approximately 11 MPa, and has suggested a 2017 in-service date. However, very little design work has been completed. PBMR has not previously designed a nuclear power plant. This lack of experience will likely result in extended design times, and could also result in above average construction and initial operating problems. It is unlikely that the PBMR organization could support both 375 MWth direct cycle and 500 MWth steam generating designs, in parallel.

The first commercial PBMR unit to be constructed following the completion of the PBMR demonstration plant will be a 'first-of-a-kind' (FOAK), and can be expected to experience a number of construction delays and technical problems, which has been the case with many FOAK units. HTGRs have been licenced in Germany and the US. A construction licence has been issued for a commercial HTGR in China, and the PBMR is currently undergoing regulatory review in South Africa. The PBMR should be licencable in Canada. However, the licencing process could be time consuming due to the lack of CNSC experience with HTGR technology, and the relatively weak international experience base, including the inexperience of the South African regulator.

A presentation covering the applicability of PBMR to the Oil Sands is presented in Appendix O. The PBMR has the potential of serving future thermochemical water splitting for hydrogen production, and coal liquefaction and gasification applications.

14.2 Summary

Nuclear Power Plants (NPPs) with water cooled reactors range in output from approximately 2100 MWth to 4500 MWth. Since the outputs of the larger capacity NPPs with water cooled reactors exceed the specified Oil Sands project requirements, these plants must serve more than one (1) Oil Sands project, and/or an alternate use for the surplus energy must be found if water cooled NPPs are to be constructed. Logically, the alternate use would be electricity production, as this could be readily transmitted over significant distances. Electricity demand in Alberta and the potential of accommodating large capacity nuclear power plants is discussed in Section 9.

The HTGRs (GA-HTGR and PBMR) have capacities in the 375 MWth to 600 MWth range, and are consistent with Oil Sands energy requirements. HTGR nuclear power plants can be optimized for cogeneration applications in order to avoid or minimize the requirement for CCW, and/or evaporative cooling water.

A summary of the thermal outputs of NPPs considered compared with the energy requirements identified for three (3) reference scenarios is presented in Table 8. The information provided in the Required MWth column includes the total MWth required, the MWth required as steam, and the MWth equivalent to the electricity demand. This comparison assumes that electricity demands are served by a generator that is driven by a condensing turbine exhausting steam to a condenser where it is condensed. If a back-pressure steam turbine is utilized in the case of NPPs utilizing water cooled reactors, or NPPs utilizing a helium turbine in the case of HTGRs, the thermal energy required for electricity production will be reduced by approximately 2/3.

In the case of water cooled reactors, the power required to drive turbine steam compressors to serve the in-situ applications is not included in the data provided in Table 8.

Table 8, NPP Capacity Compared with Energy Demand

NPP	Output MWth	Required MWth*	Surplus MWth
Mining			
ABWR	3926	793 / 572.5 / 220.5	3133
ACR-1000	3187	793 / 572.5 / 220.5	2394
AP1000	3060	793 / 572.5 / 220.5	2267
CANDU 6E	2080	793 / 572.5 / 220.5	1287
EPR	4500	793 / 572.5 / 220.5	3707
ESBWR	4500	793 / 572.5 / 220.5	3707
GA-HTGR	600 x 3	760 / 572.5 / 187.5	1040
PBMR	375 x 4	760 / 572.5 / 187.5	740
Integrated			
ABWR	3926	1535 / 1020 / 515	2391
ACR-1000	3187	1535 / 1020 / 515	1652
AP1000	3060	1535 / 1020 / 515	1525
CANDU 6E	2080	1535 / 1020 / 515	545
EPR	4500	1535 / 1020 / 515	2965
ESBWR	4500	1535 / 1020 / 515	2965
GA-HTGR	600 x 3	1457 / 1020 / 437	343
PBMR	375 x 4	1457 / 1020 / 437	43
In-Situ			
ABWR	3926	1631 / 1467 / 164	2295
ACR-1000	3187	1631 / 1467 / 164	1556
AP1000	3060	1631 / 1467 / 164	1429
CANDU 6E	2080	1631 / 1467 / 164	449
EPR	4500	1631 / 1467 / 164	2869
ESBWR	4500	1631 / 1467 / 164	2869
GA-HTGR	600 x 3	1607 / 1467 / 140	193
PBMR	375 x 4	1607 / 1467 / 140	(-107)

As shown in Table 2, the HTGRs (GA-HTGR and PBMR) delivering steam pressures of up to 17.3 MPa are the only NPP type with the capability of serving the in-situ Oil Sands steam demand without the need for steam compressors and/or the use of electric boilers.

A CANDU 6E NPP can be committed at an earlier date than any of the other NPPs considered. Implementation of an AP1000 NPP will take longer than for the CANDU 6E due to the longer licencing period. However, the AP1000 is a modern plant with passive core cooling and containment cooling features, simplified construction and operations features, and extensively modularization to facilitate shipping the modules by road or rail. In addition, the AP1000 offers lower capital and Operations and Maintenance costs than the CANDU 6E. The available steam pressure provided by the AP1000 is significantly higher than the CANDU 6E (5.8 MPa vs. 4.6 MPa).

Similar to the AP1000, the ESBWR is a modern design that incorporates extensive passive features. In comparison with the AP1000, the ESBWR's disadvantage with respect to Oil Sands requirements is its higher capacity (almost 50% greater). However, the ESBWR affords modest capital and operations cost advantages through economy of scale.

The HTGRs (GA-HTGR and PBMR) are more closely matched to Oil Sands project energy quantity requirements than water cooled reactors and facilitate the use of multi unit stations, which offers operational flexibility. The HTGRs are capable of delivering steam at pressures that meet all Oil Sands requirements, facilitating distribution over a large geographic area, and over a range of cogeneration options. Although the HTGRs can be designed in any capacity (from approximately 25 MWth to 600 MWth for the prismatic core, and from 25 MW to 500 MWth for the pebble bed), the largest capacity HTGRs offer significant economies of scale in both capital and operating cost.

The above is reflected in the NPP Evaluation Summary (see Table 19, Table 20, and Table 21). The evaluation summary provides an overview of the relative merits of available NPPs, and indicates that the two (2) HTGR NPPs are best suited for meeting the Oil Sands energy demands.

15 Nuclear Power Implementation Prerequisites

15.1 Site Selection & Acquisition

Site selection involves the identification and preliminary evaluation of potential nuclear power plant sites, and the evaluation of the merits of these sites relative to energy user demands. Evaluations made during site selection include preliminary geotechnical assessment, assessment of transportation corridors for construction and operation, determination of water availability, and the evaluation of environmental factors. Site selection generally requires approximately two (2) years to complete, and an expenditure of between $15M and $30M. CNSC site evaluation criteria for new nuclear power plants are contained in the draft Regulatory Document RD-346 (ref. [7]). Site acquisition costs can be extremely high in some areas (e.g., Florida) but are anticipated to be reasonable in the Oil Sands region. The AP1000 Siting Guide is provided in Appendix Q. This siting guide contains typical siting requirements for NPPs that utilize water cooled reactors, with appropriate adjustments based on NPP capacity.

15.2 Site Qualification

An extensive site qualification program is a prerequisite for obtaining a nuclear power plant construction licence. The site qualification program includes geo-technical evaluations, and establishing historical seismic and climatic conditions (i.e., wind, rain, temperature ranges, etc.), ground water characteristics and history. The site evaluation provides one (1) input to the environmental studies.

A site evaluation can be completed to encompass a number of nuclear power plants at the site.

A full site evaluation generally requires between two (2) and three (3) years to complete, and an expenditure in the range of $30M to $40M. Both the site qualification schedule and the cost are site specific, and have a large variance. The cost and schedule for site qualification is largely independent of the size or number of NPPs to be constructed.

15.3 Environmental Assessment

Both the Federal Government of Canada and the Provincial Governments require a comprehensive Environmental Assessment (EA) prior to approving the construction of a nuclear power plant. The Federal and Provincial Environmental Assessments may be jointly conducted. The EA assesses the impact of both the construction and operation of the nuclear power plant on the environment of the surrounding area (i.e., land, air and water), the transportation corridors utilized to serve construction and operations, and the transmission corridors employed to distribute the electricity. For Oil Sands applications, the corridors employed for the distribution of steam would also be included. The EA also addresses the socio-economic impact of the construction and operation of the nuclear power plant. Public hearings that include inputs from ‘interveners’ are also accommodated by the EA process. The EA is a key input to the CNSC licencing process.

An Environmental Assessment can be completed to encompass a number of nuclear power plants at the same site. However, unlike site assessments that may be valid for many years, EAs are generally valid for less than ten years, largely due to the changing socio-economic conditions of the site area, and the service corridors.

EAs typically take a minimum of three (3) years to complete. The cost varies over a wide range, and can be in the order of $20M. Both the schedule and cost are site specific, and have a large variance. The cost and schedule for EA is largely independent of the size or number of units to be constructed.

15.4 Nuclear Power Plant Licencing

Licencing requirements for new nuclear power plants in Canada are outlined in the Draft Regulatory document RD-337 (ref. [8]). Nuclear power plants in Canada are licenced by the CNSC for site and time specific applications. However, a large portion of the licencing effort is site independent and can proceed in advance of site selection. The schedule and cost of licencing a nuclear power plant is widely variable, and will be technology and site dependant. Licencing costs for NPPs could range from approximately $25M for a CANDU 6E, to $150M or more for a HTGR. The time required for obtaining a construction licence following the completion of all prerequisite activities could range from approximately two (2) years for the CANDU 6E, to five (5) years for technologies that are new to Canada.

The cost of licencing additional NPPs of the same design for construction in sequence at the same site is expected to be in the range of 20% of the first unit’s licencing cost. The licencing cost for a NPP of the same design at a new location is expected to be in the range of 35% of the first unit’s licencing cost. The cost and schedule for licencing is largely independent of the size or number of units to be constructed.

16 General Factors Affecting Nuclear Power Cost

16.1 General

The general factors impacting the cost of energy produced by a nuclear power plant are similar to those impacting the cost of energy from a hydro generating facility, in that the cost of energy in both cases is dominated by the capital cost of the facility, while fuel costs and operating costs are low. This is in contrast to the cost of energy from fossil fired generating plants where the capital component is relatively small, and the energy costs are dominated by the fuel cost. Once placed in service, nuclear power plants provide a stable energy supply cost, with minimal escalation over the life of the NPP (typically 60 years). Fossil fuel costs, on the other hand, are relatively unstable and are predicted to escalate at significant rates. Hence, the accuracy of cost comparisons between nuclear power and fossil power is highly dependant on the escalation factors utilized in predicting fossil fuel costs.

Section 18.2 provides a summary of the terminology used for presenting NPP costs.

Since the ‘Specific In-Place Cost’ dominates the cost of energy from nuclear power plants, nuclear vendors attempt to reduce this cost for their NPPs. One of the common approaches taken by vendors is to increase the NPP output. The relative Specific Overnight Cost of a nuclear plant is roughly proportional to the ratio of the power output to 0.68 of the power. Hence, the gains to be made through economy of scale are significant. This is the reason why nuclear vendors such as AREVA, General Electric and MHI have increased the output of their latest plants from the 1300 MWe range to the 1600 MWe range, and why AECL is increasing the 600 MWe Class CANDU 6 to the 1200 MWe Class ACR-1000. It is also the reason why small and intermediate capacity NPP designs such the AECL CANDU 3 (450 MWe) and the Westinghouse AP700 (760 MWe) have been dropped. Vendors are also striving to reduce the construction schedule for their plants, which serves to reduce interest during construction, and project risks.

There is also a significant Specific In-Place Cost reduction that can be realized through the economies of multi-unit installations. This cost for subsequent units of the same design at the same site, and if their in-service dates are in the range of one (1) year to eighteen months apart, is approximately 20% less than this cost for the first unit. This is why Westinghouse and AECL are offering two (2) unit reference station designs for the AP1000 and ACR-1000, respectively. A portion of the savings in the two (2) unit configuration results from the provision of common services (e.g., maintenance facilities, administration facilities, security, and chemistry laboratories). In addition, the savings in procurement and construction staff training and construction man-hours are significant.

Larger output NPPs can also take advantage of reduced operations, maintenance, and security costs (O&M Costs) relative to smaller NPPs, as these costs tend to be largely independent of NPP output. The same number of operators is required regardless of the NPP output, while the required number of maintenance and security staff increases very little with increased NPP output.

The many factors affecting significant Specific In-Place Cost include site selection, site acquisition, site qualification, site infrastructure, environmental assessment, licencing and security provisions. Since these factors are essentially independent of the NPP output and number of NPPs constructed, this gives a Specific In-Place Cost advantage to larger NPPs and multi-unit stations.

Since the cost of energy from a nuclear plant is dominated by the Specific In-Place Cost, nuclear plants are generally operated as base load facilities. This is consistent with the requirements of the Oil Sands applications. The total cost of nuclear plant operations to the owner remains essentially constant, regardless of the NPP operating output. This cost is reduced only marginally if the plant is shut down, since all the operators and maintenance staff required by the licencing basis must be kept on duty.

The output of current High Temperature Gas Reactors (HTGRs) is limited by their ability to reject decay heat to the environment without active systems to approximately 600 MW thermal for prismatic core configurations (e.g., GA-HTGR), and 500 MWth for pebble bed core configurations (e.g., PBMR), thereby limiting their ability to take advantage of economy of scale. However, the economies of multi-units can be realized if several HTGR units are constructed in parallel.

16.2 Component & Labour Costs

Nuclear power plants require an extended planning and construction period that can span more than 11 years from the date of commitment (see Figure 25 and Figure 26). For this reason, nuclear power plants are subject to the same general cost escalation of the market region. In recent years, there has been a rapid escalation in the cost of power generation projects in North America. For example, Duke Energy, a large and capable US Utility had estimated the cost of two (2) 800 MWe coal plants to be built in North Carolina in 2003 at US$ 2B. A revised estimate in 2006 placed the cost at US$ 3B. In mid 2007, one (1) unit was cancelled and the revised estimate for the remaining unit was increased to US$ 1.83B. This cost escalation is indicative of the general trend for project costs in North America. Although uncertainty is increased by the lengthy nuclear project schedules, these cost escalations are not unique to nuclear power.

17 Factors Affecting Construction Cost: Oil Sands

17.1 Component Shipping

17.1.1 Principal NPP Component Characteristics

Nuclear power plants include many large and heavy components that are not feasible to fabricate at the site, so they must be shipped to the site. These components include the following.

Steam Generators: The largest Steam Generators utilized by any of the NPPs reviewed of are those utilized by the AP1000. The AP1000 SG specifications are listed below.

a) Length: 24.4 m;

b) Diameter: 6.1 m;

c) Weight: 664 metric tons.

Pressure Vessels: The largest water cooled reactor pressure vessels are for the EPR and the ESBWR. Although the diameters of these pressure vessels are similar, the height and weight of the pressure vessel are greater. Approximate specifications are provided below. The EPR value is stated first, followed by the ESBWR value.

a) Length: 12m/21m;

b) Diameter: 6m/7m;

c) Weight: 400/580 metric tons.

For comparison, the AP1000 pressure vessel specifications are:

a) Length: 10.3m;

b) diameter: 4.5m;

c) Weight: 296 metric tons.

Due to their relatively low power density, HTGR pressure vessels have larger diameters and greater lengths than water cooled pressure vessel reactors. However, they have comparable weights due to the thinner wall construction that results from lower operating pressure. Since the HTGR vendors did not provide pressure vessel design information, the values provided below are SLN estimates of typical HTGR pressure vessel specifications.

a) Length: 26m;

b) Diameter: 9m;

c) Weight: 560 metric tons.

Calandria Assemblies: The CANDU 6E and the ACR-1000 utilize low pressure calandria assemblies to contain the heavy water moderator and to support the fuel channels. The fuel channels can be installed at site, thereby reducing the shipping weight. The diameter of the calandria assemblies of the CANDU 6E and ACR-1000 are both approximately 7m.

Low Pressure Turbines: The largest Balance of Plant (BOP) components for water cooled reactors that are dedicated to electricity production are the low pressure turbines. For the AP1000, ACR-1000, and CANDU 6E, the LPs are approximately 11m in diameter and 10m in length.

General: Other, large components in the NPP include the deaerator storage tanks. These typically range from 4m to 5m in diameter, and 30 m in length. However, their weight is low relative to Steam Generators and pressure vessels.

17.1.2 Shipping Summary

Shipping large and heavy components from their points of manufacture to the designated Oil Sands location may require the construction of special roadways and other infrastructure to facilitate shipping. Shipping times may also be set by environmental considerations (ground frost thickness, weather, etc.). Detailed transportation studies are typically completed as part of the site qualification program.

The preferred shipping method for most nuclear power plant components is by rail. Main line rail service is available from Vancouver and Duluth Minnesota to Edmonton. However, the horizontal clearance is limited on these routes (approximately 4 meters from Vancouver and 4.3 meters from Duluth). The highest capacity rail car available for shipping nuclear components is Schnabel's 36 axle rail car designed by Combustion Engineering, and currently owned by Westinghouse. This special rail car has a capacity of over 1000 tons, and can accommodate load lengths of up to 35 meters. Although there are small rail lines serving the Oil Sands region from Edmonton, no information was obtained on their capabilities. A detailed shipping strategy will be required as part of the project planning and scheduling.

17.2 Environment

The working environment (i.e., temperature, wind, precipitation, snow conditions, etc.) impacts all the activities taking place outside of the enclosed structures. The environmental conditions affect the project schedule by limiting the available work periods for some activities. For example, pouring large volumes of concrete may be precluded during some months by low temperature conditions, and severe weather conditions may preclude the use of large cranes at times. Adverse weather conditions can reduce worker productivity, and may also constrain and restrict the operation of some construction equipment, such as trucks and earth moving equipment. All environmental factors must be considered during the preparation of project schedule and project man-power estimates, and in the risk assessment.

Environmental factors can also impact shipping schedules and site preparation schedules. For example, excellent progress was made in winter during the construction of the James

Bay hydro projects, but most work had to be stopped in the spring when the frost left the ground.

17.3 Trades & Labour Availability & Wage Rates

The escalation of major projects in North America that include refurbishment activities scheduled for Canadian nuclear power plants, and developments in the Oil Sands region, will place increasing demands on skilled labour resources. Currently, there are Combined Operating Licence (COL) applications before the NRC in the US covering the construction of eight (8) nuclear power plants (i.e., two AP-1000s, two ABWRs, two ESBWRs and two EPRs). The construction of these plants, if they proceed, will place large demands on North American skilled trades and engineering resources from all disciplines. The projected demand for workers in the Oil Sands region is already very high without including nuclear power plant demands. For example, Alberta's Industry Minister Iris Evans stated in April of 2007 that the province will require 400,000 additional workers over the next 10 years in addition to filling a current shortfall of approximately 100,000 workers. Attracting skilled human resources to the remote, northern Alberta Oil Sands region will require payment of salary premiums and signing incentives. The cost of labour (i.e., wages, signing bonuses and other incentives) must be factored into the project cost estimates and risk assessments.

17.4 Housing & Related Infrastructure

A construction force of as many as 1500 people required by a nuclear project must be housed in close proximity to the construction site. If workers bring their families, local facilities such as shopping and entertainment areas and schools must be available or provided. Typically, for NPPs constructed in relatively remote areas, a construction village is built to accommodate the construction workers and their families. This infrastructure will be relatively expensive in the Oil Sands region.

17.5 Construction Materials

It is anticipated that all materials necessary for constructing the nuclear power plant(s) will be shipped to the construction site from locations throughout Canada and the US, with the possible exception of concrete aggregate. NPP construction requires extremely large volumes of concrete for the containment building and/or shielding structure, and the turbine hall foundations. The aggregate specifications are directed at assuring a 60 year operating life and delayed decommissioning, and are very specific and demanding. It is not uncommon for aggregate to be imported or hauled over long distances. A dedicated concrete plant is generally constructed nearby to serve the NPP site construction demands. The sourcing of aggregate must be addressed in the Project Execution Plan, and factored into the project cost estimates.

17.6 Cooling & Cooling Water

NPPs dedicated to electricity production require a significant volume of water to provide condenser cooling. The water flow required by a once-through condenser with an eight (8) degree Celsius rise in Condenser Cooling Water (CCW) temperature is approximately 3000 kg/sec for each 100 MWth of heat rejected to the condenser. In once-through CCW applications, the CCW flow can be returned to the water source. If evaporative natural convection or forced draft cooling towers are employed for CCW cooling, the water demand would be approximately 44 kg/sec for each 100 MWth of heat rejected, and this water would be lost to the atmosphere.

It is anticipated that any NPP constructed in the Oil Sands region will employ either natural draft of forced draft cooling towers. In general, natural draft cooling towers are used in cooler regions (e.g., Tennessee), and forced draft towers in warm climates (e.g., southern Arizona). The operation of cooling towers, including the prevention of freezing during plant outages, is problematic in cold climates and adds to the capital cost and operating cost.

18 Nuclear Power Plant Capital Costs

18.1 Overnight Construction Cost Distribution

The Overnight Construction Cost components of a water cooled nuclear power plant dedicated to electricity production are generally considered under the numbered groupings defined below. The approximate fraction of total plant capital costs represented by each group is provided in brackets for each cost type (i.e., item). The costs do not include Owner's Costs, the cost of the first fuel load, and heavy water if applicable. The cost distribution is shown in Figure 19.

The capital cost distribution for HTGRs is expected to be similar to water cooled reactors. GA indicated that power production facilities represent approximately one third of the Overnight Construction Cost of the GA-HTGR, which is of the same order as the combined turbine island and BOP costs presented below.

1. Nuclear Island costs (50%) include the following;

   a) Civil Works, including excavation and building structures;

   b) Mechanical, Electrical and C&I equipment;

   c) Labour for erection of mechanical, electrical and C&I equipment;

   d) Detailed Engineering for the nuclear island;

   e) Field engineering and commissioning.

2. Turbine Island costs (20%) include the following;

   a) Civil Works including excavation and structures;

   b) Mechanical, Electrical and C&I equipment;

   c) Labour for erection of mechanical, electrical and C&I equipment;

   d) Detailed Engineering for the turbine island;

   e) Field engineering and commissioning.

3. Balance of Plant costs (10%) include the following;

   a) Civil Works including cooling towers/pump houses, miscellaneous structures, drainage, water treatment plant, sanitary and domestic systems, site improvements;

   b) Mechanical, Electrical and C&I equipment;

   c) Labour for erection of mechanical, electrical and C&I equipment;

   d) Detailed Engineering for the turbine island;

   e) Field engineering and commissioning.

4. Direct Owner's costs (10%) include the following;

   a) Project Management;

   b) Applicable Insurance;

   c) NPP spare parts;

   d) Staff (operations and maintenance) training;

   e) Training facilities including simulator;

   f) Construction and operations staff security and fit for duty checks;

   g) Preparation of commissioning and operations manuals and procedures;

   h) NPP commissioning.

5. Contractor costs (10%) include the following;

   a) Project Management and Administration;

   b) Procurement;

   c) On-site Engineering Support;

   d) Shipping costs, including insurance;

   e) Staff and worker travel and relocation allowances;

   f) Staff and trades training and qualification.

6. Project Owner's cost: The following efforts are the responsibility of the owner and are not included in the Direct Owner's cost. Since they are widely variable and cannot reliably be allocated as a fraction of total plant costs, they are not included in the Capital Cost Distribution allocation. These costs include the following.

   a) Site selection;

   b) Site acquisition;

   c) Site evaluation;

   d) Site design activities;

   e) Infrastructure (roads, docks, rail lines, transmission lines, worker housing, construction facilities, etc.);

f) Site security (fencing, guardhouses, security systems);

g) Environmental assessment;

h) Licencing;

i) Public and media relations;

j) Applicable taxes;

k) Interest during construction.

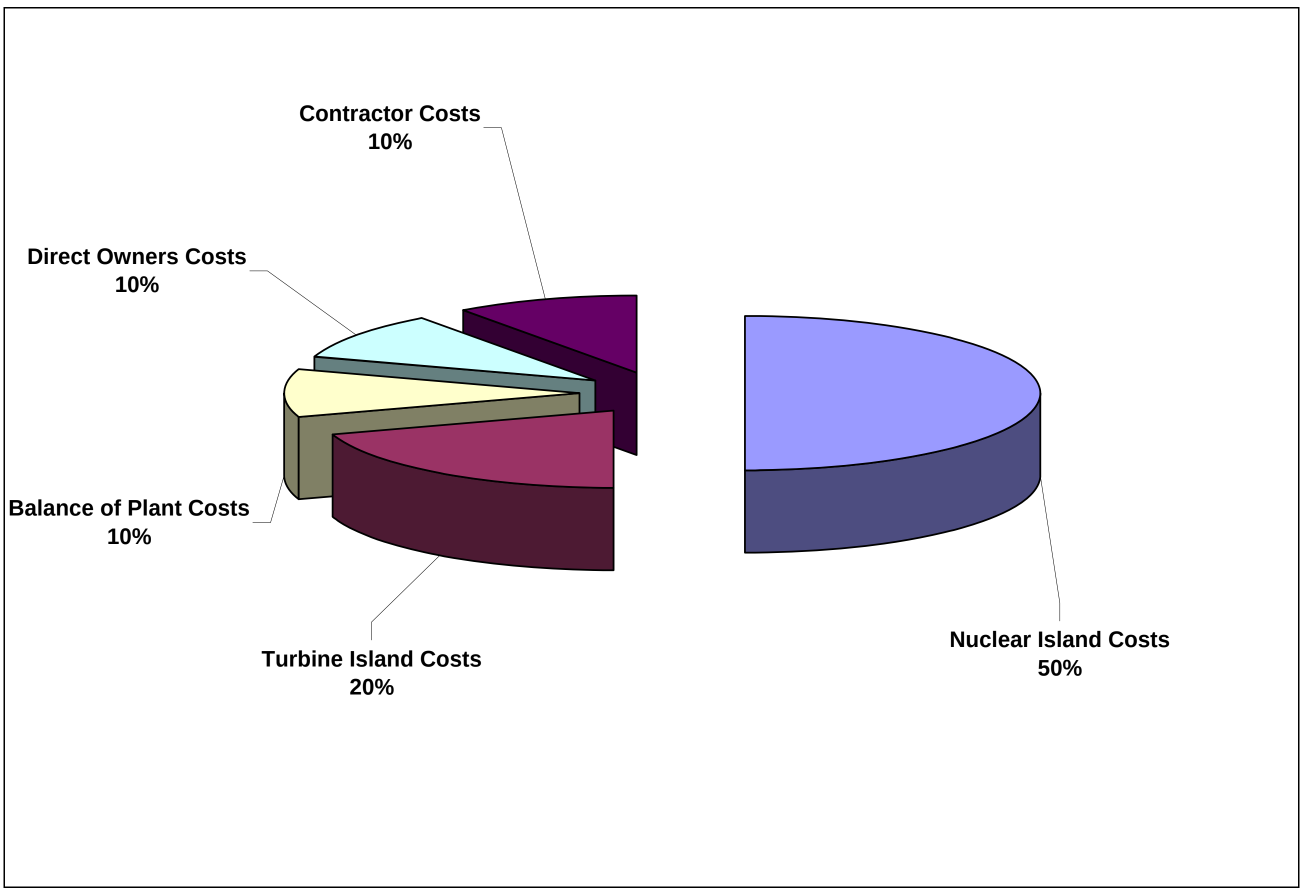


Figure 19, Typical Capital Cost Distribution for Nuclear Power Plants

18.2 NPP Costs Terminology Employed

The following terms are employed in the cost discussions and analysis presented in this report.

- **Overnight Cost:** The cost of the NPP excluding all Owner's costs;
- **Specific Overnight Cost:** The Overnight Costs divided by the net output of the NPP. Specific Overnight Capital Costs can be expressed in $/MWe (the usual method) or in $/MWth;
- **Owner's Cost:** All costs excluding the Overnight Capital Cost, Federal and Provincial Taxes, and site acquisition costs are normally included in the Owner's Cost but are excluded in this report due to the uncertainty in these costs;
- **In-Place Cost:** The *total* cost of the NPP to the Owner. Federal and Provincial Taxes, and site acquisition costs are normally included in the In-Place Cost but are excluded in this report due to the uncertainty in these costs;
- **Specific In-Place Cost:** The total cost of the NPP to the Owner divided by the output of the NPP. Specific In-Place Costs can be expressed in $/MWe (the usual method) or in $/MWth;
- **Operations and Maintenance Cost (O&M):** the cost of operating and maintaining the NPP including security staff costs, excluding fuel cost and jurisdictional levies to cover decommissioning and spent fuel disposal;
- **Specific Operations and Maintenance Cost:** The O&M Costs divided by the output of the NPP. Specific O&M Costs can be expressed in $/MWe (the usual method) or in $/MWth;
- **Fuel Cost:** The total cost of new fuel for the NPP;
- **Specific Fuel Cost:** The fuel cost divided by the output of the NPP;
- **Fuel Cycle Cost:** The total of the front end and backend fuel cost;
- **Specific Fuel Cycle Costs:** The Fuel Cycle Cost divided by the NPP output.

18.3 Nuclear Power Plant Specific In-Place Capital Costs

18.3.1 Background

NPP In-Place Cost is impacted by many factors that are unrelated to the NPP technology or its design. An independent study completed in 1992 (proprietary information) that investigated and compared the cost of the CANDU 6 NPP constructed at Pt. Lepreau in New Brunswick with the 600 MW Class Westinghouse NPPs, and the Turkey Point 3 and 4 NPPs constructed in Florida. The study concluded that, in this case, the costs incurred by the Turkey Point project that were not incurred by Pt. Lepreau and that were independent of the technology constituted approximately 23% of the Turkey Point costs. These factors included the following.

Profit: The suppliers, Architect Engineers, and NSSS vendor made a "sound"' profit on the Turkey Point plants, while AECL (the Pt. Lepreau vendor that also provided most AE functions) made a very low profit;

Taxes: The Florida plant paid all applicable federal and state taxes, while the NB plant was exempt of Federal and Provincial taxes;

Wages for Skilled Labour: Wage rates at the time of construction (1975 to 1982) were substantially higher in the US than in Canada;

Interest During Construction: The Florida plant relied on commercial paper, while the NB plant took advantage of provincial government financing rates;

All factors, including the above, must be considered when developing the In-Place capital cost estimates for NPPs constructed in the Oil Sands region.

This study relies on the information provided by vendors, published information, proprietary information held by SLN, and limited analysis.

SLN has been unable to obtain comprehensive cost information from the nuclear vendors, including allocations of cost based on materials, components and man-hours. SLN has concluded that this information will only be made available by the vendors in response to a formal Request For Proposal (RFP).

No nuclear power plants have been constructed in North America or Europe in recent years, although two EPRs are currently under construction in Europe (Finland and France). Hence, reliable NPP cost data is largely limited to what is available from the Republic of South Korea, and from Japan. Table 9 provides Specific In-Place Cost information for the NPPs recently constructed in these countries. The Specific In-Place Cost reduction associated with the construction of a second unit of the same design at the same site is shown by the data. However, due to country specific differences and currency exchange uncertainties, the information is not directly applicable to the nuclear industry in the US or Canada. In addition, all of the NPPs listed were constructed at sites with a number of operating nuclear power plants and an existing nuclear infrastructure. NPPs plants that are constructed under 'greenfield' conditions (greenfield sites are those with no current nuclear power plant) can be expected to incur higher costs. Other independent and utility based sources are projecting substantially higher Specific In-Place Costs for new nuclear plants in the US (ref. [3]). Since a new nuclear power plant has not been committed in North America since the Darlington station operated by Ontario Power Generation (OPG) was committed in the early 1980s, there will be substantial uncertainties for NPP cost estimates until a new nuclear power plant construction project has largely been completed in Canada.

Table 9, Recent Construction In-Place Cost Experience

Plant	Capacity (MWe)	Cost (2007 $/per kW)
Onagawa 3	825	3332
Genka 3	1180	3656
Genka 4	1180	2711
Kashiwazaki-Kanwa 6	1356	3167
Kashiwazaki-Kanwa 7	1356	2707
Yonggwang 5	1000	2352
Yonggwang 6	1000	2290
Harnacka 5	1380	2978
Shika 2	1358	2922

In Table 9, the cost of the last two (2) units in Japan was determined using a conversion of 117 yen to the US dollar. Previous Japanese units were converted using an exchange rate of 159 yen to the US dollar.

The contract for Guangdong 3 and 4 was signed by AREVA and the Chinese utility on November 27, 2007. The stated $12B contract value (Overnight Construction Cost of approximately 4000 $/kW) provides for fuel supply over 15 years, but does not include the Owner's cost.

The information provided in Table 9 for the completed nuclear power plants was obtained from the MIT report 'The Future of Nuclear Power' (ref. [4]).

18.3.2 Reference NPP Specific Overnight Costs

NPP vendors generally provide estimates of the Specific Overnight Costs (terminology varies), and leave the buyer/utility to determine the Owner's cost.

AREVA provided an indicative Specific Overnight Cost of 2000 $/kWe for an EPR constructed in the US, assuming that four (4) EPR NPPs are built in the US during the same period. This estimate utilizes the cost structure defined in Section 18.1. The AREVA estimate assumes the use of natural draft cooling towers, and by definition excludes the Owner's cost. A presentation made by AREVA in 2007 (ref. [26]) gave the Specific Overnight Cost for the EPR in Finland as $2500/kW, and projected the Specific Overnight Cost of EPR units in France based on the construction of 10 units as $2040/kWe (using a conversion rate of US$ 1.5 per Euro).

Westinghouse provided an indicative Specific Overnight Cost (low range estimate) for the AP1000 as 2600 $/kWe, assuming that a two (2) unit AP1000 NPP is constructed, with these units preceded by a two (2) unit AP1000 constructed in the US. The Westinghouse estimate includes a small portion of the Owner's cost (e.g., a full scope simulator), and is based on the use of force draft cooling towers. Westinghouse indicated that the Specific Overnight Capital Cost of a single AP1000 would be 60% of the two (2) unit station's Specific Overnight Cost, yielding a Specific Cost of approximately 3100 $/kWe for a single unit AP1000. This is consistent with other available information indicating that a single unit would cost approximately 20% more to construct than the (per unit) costs of a twin unit constructed during the same time period.

Westinghouse indicated the 2600 $/kWe Specific Overnight Cost provided was at the lower end of the possible range for this cost. SLN therefore added a 10% contingency to this number provided by Westinghouse, yielding a Specific Overnight Cost of 2860 $/kWe for a two (2) unit AP1000 station, and a Specific Overnight Cost for a single unit AP1000 of approximately 3400 $/kWe. Study of the EPR and AP1000 designs by SLN, with allowance for economy of scale, sequential unit construction, and simplifications featured in the AP1000 design indicate no basis to suggest the Specific Overnight Cost of the EPR would be lower than the Specific Overnight Cost of a twin unit AP1000. This is consistent with a recent US study which determined that the AP1000 Specific Overnight Capital Cost was slightly lower than for the EPR (information received through private communications).

AECL did not provide any cost information on either the CANDU 6E or the ACR-1000. However, the Canadian Energy Research Institute (CERI) in reference [2] indicates that the Specific Overnight Cost of a twin CANDU 6 unit is 2972 $/kWe (in 2003 dollars), including the cost of heavy water. This is approximately 3200 $/kWe (in 2007 dollars) and is consistent with the reference AP1000 cost of 2860 $/kWe. On the same basis as for the AP1000, the Specific Overnight Cost for a single unit CANDU 6 E is projected to be 3840$/kWe. A review of the available ACR-1000 information indicates it is very unlikely for the ACR-1000 to offer a Specific Overnight Cost that is lower than for the AP1000.

GE declined to provide cost estimates for either the ABWR or the ESBWR. Based on the reviews of available design information by SLN, SLN expects that the ABWR Specific Overnight Cost will be approximately 10% higher than for the EPR, while this cost for the ESBWR will likely be approximately the same as for the twin unit AP1000.

General Atomics have estimated the Specific Overnight Cost of a direct cycle, 600 MWth HTGR which excludes the Owner's Cost as approximately 1800 $/kWe, assuming that a four (4) unit GA-HTGR station is constructed. PBMR initially indicated that the Specific In-Place Cost of a 500 MWth/220 MWe PBMR module is approximately 2000 $/kWe . Based on a first order cost estimate by SLN (see Appendix K), SLN believes the estimates provided by GA and PBMR are low by substantial margins. Based on the analysis presented in Appendix K, the Specific Overnight Cost for an 1100 MWe 6 module PBMR station could be in the range of 8000 $/kWe. When presented with SLN estimates, Shaw-Westinghouse revised the PBMR Specific In-Place Capital Cost estimate to a $3500 to $5000 per kilowatt hour range. The estimated Specific Overnight Cost for the Modular Thermal Helium Reactor (MOTHER), the first published direct cycle HTGR design, was 1620 $/kWe in 1987 dollars or approximately 2700 $/kWe in 2007 dollars, for an integrated three (3) unit nuclear power plant. The MOTHER design incorporates several features that serve to reduce costs relative to the PBMR.

No HTGRs have been constructed since the early 1980s, and direct cycle HTGRs have never been constructed. Hence, there is no reference cost base data available. As with the water cooled reactors, reliable Specific Overnight Cost estimates for the HTGRs will not be available until these units are actually constructed. Specific Overnight Cost estimates can be refined with effort by the HTGR vendors. US Department of Energy (i.e., DOE) contracts were recently awarded to Westinghouse and GA that cover early design work on concepts for a HTGR dedicated to hydrogen production. A demonstration plant will potentially be constructed at the Oak Ridge National Laboratories (ORNL) site. This work may result in revised capital cost estimates by the vendors.

Due to the uncertainly of HTGR Specific Overnight Cost estimates provided by the HTGR vendors and SLN's first order Specific Overnight Cost estimate, an intermediate value of $4000/kW for a four (4) unit station is being used as a reference Specific Overnight Cost in this study for both the GA-HTGR and the PBMR concepts in Table 10.

The labour and productivity rates for both the EPR and AP1000 Specific Overnight Cost estimates are based on 'Centerville USA' cost factors, while the CANDU 6 estimates by CERI are based on central Ontario factors. Since the construction labour costs are expected to be significantly higher in the Oil Sands region, some variations are anticipated between the plants. The AP1000 has the greatest degree of modularization, with modules that are shippable by road or rail. Hence, the AP1000 design facilitates a greater amount of off-site labour than the other water cooled NPPs considered (see Appendix D). Since no Vendor supplied cost breakdowns indicated any construction man-hours, it is not possible to precisely define the labour cost increase that should be attributed to the Oil Sands environment. However, the total cost of construction labour including trades and management staff has historically been in the range of 40% of the Overnight Cost. A focus on modularization and prefabrication may reduce this fraction. In the absence of a detailed breakdown on the mix of trades, general labourers and others required for construction, it is difficult to determine the additional cost associated with construction in the Oil Sands region. Assuming that labour costs average 25% more in the Oil Sands region than in Ontario and the central US, the Specific Overnight Cost for the nuclear power plant would increase by 10%. A further escalation of 2% (arbitrary) to allow for increased shipping costs and insurance results in a net Specific Overnight Cost increase of 12%.

A summary of the Specific Overnight Costs per kWe and per kWth are provided in Table 10 for both Ontario and the Oil Sands region.

The Specific Overnight Costs presented on the basis of $/MWth include the cost of electrical generation equipment that is normally provided with the NPP. Net thermodynamic steam cycle efficiencies with an allowance for station loads utilized in determining the Specific Overnight Costs in $/MWth are 34% (for CANDU 6E), 35% (for ACR-1000, AP1000, and EPR), and 36% (for ABWR and ESBWR).

Table 10, Summary of Specific Overnight Cost

Item	Description	Cost (2007 $/kWe) Ontario/Oil Sands Region	Cost (2007 S/kWth) Ontario/In Oil Sands Region
ABWR	Single Unit	3150/3528	1134/1270
ACR-1000	Two Unit	2860/3002	1001/1121
	Single Unit	3400/3808	1190/1332
AP1000	Two Unit	2860/3203	1001/1121
	Single Unit	3400/3808	1190/1332
CANDU 6E	Two Unit	3200/3584	1088/1218
	Single Unit	3840/4300	1305/1461
EPR	Single Unit	2860/3203	1001/1121
ESBWR	Single Unit	2570/2878	925/1036
GA-HTGR	Four Unit	4000/4480	1680/1881
	Two Unit	4800/5376	2016/2257
PBMR	Four Unit	4000/4480	1680/1881
	Two unit	4800/5376	2016/2267

18.3.3 Reference NPP Owner's Costs

The Owner's cost, which includes the items listed in Section 18.1, items d) and f), are difficult to estimate accurately. The activities described in item d) typically represent approximately 10% of the Overnight Specific Capital Cost. The cost of the activities described in item f) is widely variable, and many activities are relatively independent of the plant Overnight Cost. Based on discussions with those who have studied the Owner's Costs of nuclear power plants in the US, an Owner's Cost of 30% for activities described in items d) and f) that exclude Federal and Provincial taxes and the site acquisition cost components of the Overnight Cost is considered as reasonable for a well executed nuclear project. Owner's Costs can increase substantially if the project in-service date is significantly delayed.

Greater accuracy in determining the Owner's Cost will require a comprehensive study to identify the precise site infrastructure costs and related activities, applicable taxes, interest during construction, and the cost of various site and licencing activities.

18.3.4 Reference NPP In-Place Costs

The resulting Specific In-Place Costs, excluding applicable Federal and Provincial taxes and site acquisition costs are summarized in Table 11. The Specific In-Place Costs presented in Table 11 on the basis of $/MWth include the cost of electrical generation equipment that is normally provided with the NPP. Net thermodynamic steam cycle efficiencies, with an allowance for station loads, utilized in determining the Specific In-Place Costs in $/MWth are 34% (for CANDU 6E), 35% (for ACR-1000, AP1000, and EPR), and 36% (for ABWR and ESBWR).

Although higher capital costs may make the current HTGRs uneconomical for electricity production in high capacity grid situations, HTGRs may prove to be economical in process heat applications that provide for high energy utilization.

Table 11, Summary of Specific In-Place Cost in the Oil Sands Region

Item	Description	Cost (2007 $kWe)	Cost (2007 $kWth)
ABWR	Single Unit	4586	1650
ACR-1000	Two Unit	4164	1457
	Single Unit	4950	1735
AP1000	Two Unit	4164	1457
	Single Unit	4950	1735
CANDU 6E	Two Unit	4659	1584
	Single Unit	5591	1956
EPR	Single Unit	4164	1457
ESBWR	Single Unit	3742	1347
GA-HTGR	Four Unit	5824	2446
	Two Unit	6989	3935
PBMR	Four Unit	5824	2446
	Two Unit	6989	3935

19 Nuclear Power Plant Operations Costs

19.1 Staffing

Staffing levels at nuclear power plants can vary widely, and depend on utility specific operating procedures and approaches. Staffing levels at US nuclear power plants were reduced by approximately 20% between 1997 and 2005 (ref. [12]) as US utilities focused on efficiency, taking advantage of operating experience and available new technologies. Staffing levels at Canadian nuclear power plants either remained constant or increased during the same period.

In the US, the average staffing level at two (2) unit nuclear power stations in 2007 was 1104, which includes security staff. Goodnight Consulting Inc., an independent consulting firm with extensive experience in reviewing nuclear power plant performance and costs, has estimated the operating staff requirements for a two (2) unit AP1000 station as 921 (460.5 staff per unit), and has projected a drop to 737 for each pair of units in a station with two (2) AP1000 two (2) unit NPPs (i.e., total of four units, with 368.5 staff per unit). AREVA has indicated that a single EPR constructed at a greenfield site will require a total staff of 414. The AREVA numbers are inconsistent with the Goodnight Consulting numbers, as the staffing level required to operate and maintain a single unit EPR will certainly be higher than for one (1) unit of a two (2) unit AP1000 plant. SLN believes that Goodnight Consulting staffing estimates are realistic, and that a single unit EPR at an ‘average’ US location will require approximately 595 staff.

AECL did not provided staffing level estimates for the CANDU 6E or the ACR-1000. The total number of operating staff for a CANDU 6 station in Canada is approximately 675 (verbal communication from Hydro Quebec). The actual staff levels at the Ontario plants are significantly higher. On this basis, SLN estimates that staff levels for a two (2) unit CANDU 6E would be approximately 1040 (520 per unit). Staff levels at a two (2) unit and single unit ACR-1000 stations are likely to be approximately the same as for the two (2) unit and single unit CANDU 6E stations.

GE did not provide staffing information for the ABWR or the ESBWR. A review of the designs suggests that the required staff level for the ABWR will be approximately the same as for the EPR and that the required staff levels for the ESBWR will be approximately 10% more than for a single unit AP1000.

PBMR indicated that a total staff count of less than 50 would be required to operate and maintain a single 500 MWth PBMR module in either a steam only production mode or a cogeneration mode, including security staff. Analysis by SLN indicates that PBMR’s staff count is unrealistically low. For example, assuming that two (2) operators are on duty at all times (a minimum regulatory requirement), ten (10) operating staff would be required based on a five (5) shift per week operation. Similarly, a minimum of two (2) dedicated security staff will be required at all times, requiring ten (10) staff on a five (5) shift basis. However, assuming the regulatory requirement for two (2) operators to operate more than one (1) unit at a time, and other simplifications inherent in the PBMR design, a staff level of approximately 250 may be reasonable for a four (4) unit PBMR facility.

A summary of estimated staff requirements is provided in Table 12.

Table 12, Summary of Estimated NPP Staff

Item	Description	Estimated Staff
ABWR	Single Unit	595
ACR-1000	Two Unit	1040
	Single Unit	675
AP1000	Two Unit	921
	Single Unit	595
CANDU 6E	Two Unit	1040
	single Unit	675
EPR	Single Unit	595
ESBWR	Single Unit	654
GA-HTGR-	Four Unit	250
	Two Unit	150
PBMR	Four Unit	250
	Two Unit	150

19.2 Operations & Maintenance Costs

Specific Operations and Maintenance (O&M) costs for the US nuclear fleet during the five (5) year period from 2002 to 2006 are presented in Table 13. The information in this table is taken from the 'Electric Power Annual 2006' prepared by the US Energy Information Administration (EIA) (ref. [5]). The data includes single unit and multiple unit nuclear power stations (PWRs and BWRs). O&M and fuel costs have remained fairly constant over the years. The total cost for O&M and fuel in 1995 was $20.39 m/kW hour. The average O&M cost for US plants in 2006 was $14.51m/kW hour. Costs are given in mills per kilowatt hour. The lower cost results from improved capacity factors, and the maturity of operations and maintenance procedures.

Table 13, Specific Operations, Maintenance & Fuel Costs for US Plants (2002 to 2006)

Item	Costs ($m/kW Hour)				
Year	**2006**	**2005**	**2004**	**2003**	**2002**
Operations	8.83	8.39	8.30	8.86	8.54
Maintenance	5.68	5.23	5.38	5.23	5.04
Total O&M	14.51	13.62	13.68	14.09	13.58
Fuel	4.85	4.54	4.58	4.60	4.60
Total O&M and Fuel Cost	19.46	18.16	18.26	18.69	18.18

The average 2006 Specific O&M Cost for nuclear plants in the US ($14.51 m/kWh) is utilized as the baseline for determining the O&M costs for the PWR and BWR plants for the purposes of this study. SLN estimates that O&M cost reductions due to economy of scale (EPR, ABWR, and ESBWR) and twin unit operation (AP1000) combined with plant simplifications as applicable to the various designs should reduce the O&M costs for the PWR and BWR plants considered by approximately 15%. This results in an estimated O&M cost of $12.34 m/kW hour for plants located in the lower 48 States. O&M costs for a single unit AP1000 is expected to be 20% greater.

AECL did not provide cost information on either the CANDU 6E or the ACR-1000. However, the Canadian Energy Research Institute (CERI) (ref. [2]) indicates that the estimated Specific O&M Costs for twin unit CANDU 6 and ACR-700 stations are $12.90/net MWh/yr and $10.85/net MWh/yr, respectively, for plants located in Ontario. These costs represent Specific O&M costs of approximately $14 m/kWh for the CANDU 6, and $11.75 m/kWh for the ACR-700 in 2007 dollars. The Specific O&M costs for a single unit CANDU 6 are estimated to be 20% greater than for the twin unit station, resulting in a Specific O&M cost in 2007 dollars of approximately $16.8 m/kWh.

The Specific O&M Cost for a two unit ACR-1000 for purposes of this study, for plants located in Ontario is assumed to be 10% greater than those for the AP1000 in a US location. The increase in Specific O&M Cost allows for heavy water loss, the additional maintenance required by the employment of active safety related cooling systems, the heavy water systems, and the on-power refuelling system.

SLN was unable to obtain reliable Specific O&M Cost estimates for the HTGR plants. However, a detailed review that included the number of components involved suggests that the Specific O&M Cost for a four unit GA-HTGR or PBMR station are very unlikely to be less than those of a twin unit AP-1000. Refer to Appendix I. Hence the Specific O&M Cost for HTGR 4 unit stations for the purposes of this study are assumed to be the same as those for a twin unit AP1000. Specific O&M Cost for two unit GA-HTGR or PBMR plants are assumed to be 20% greater than for the four unit stations. Accurate O&M costs for the HTGR facilities will not be known until the designs are complete and the staffing plans are confirmed.

A summary of the Specific O&M Costs is provided in Table 14.

Table 14, Summary of Specific O&M Costs for NPPs Located in Ontario

Item	Description	Cost (2007 $m/kWh)
ABWR	Single Unit	12.34
ACR-1000	Two Unit	11.75
	Single Unit	14.10
AP1000	Two Unit	12.34
	Single Unit	14.80
CANDU 6E	Twin Unit	14.60
	Single Unit	17.5
EPR	Single Unit	12.34
ESBWR	Single Unit	12.34
GA-HTGR	Four Unit	12.34
	Two unit	14.80
PBMR	Four Unit	12.34
	Two Unit	14.80

19.3 Fuel Cycle Costs

19.3.1 Front End Fuel Costs

The Front End fuel costs include the total cost of new fuel. The average Specific Fuel Cost for PWRs and BWRs operating in the US in 2006 was $4.85m/kW hour (ref. [5]). This is approximately $4.95/m/kWh in 2007 dollars. AREVA indicated that the US EPR fuel cost would be $5.57m/kW hour, and claimed a fuel cost reduction relative to a fuelling cost of $6.23m/kW hour for existing 4-loop PWRs. The latter number is approximately 28% higher than the value provided (ref. [5]). Fuel cost tends to be slightly lower for larger NPPs than for smaller NPPs due to reduced neutron losses from the core. For this reason, the Specific Fuel Cost for the large 4-loop plants should be slightly lower than the US average. This discrepancy may result from the consideration of non-US PWRs, and from currency exchange factors. However, there is no basis to suggest that EPR Specific Fuel Cost should exceed the US average fuel cost for NPPs operated in North America. Westinghouse provided the basis for calculating Specific Fuel Cost for the AP1000. Assuming the current costs for uranium Separative Work Units (SWU) and fabrication, the AP1000 Specific Fuel Cost is comparable with the US average. For purposes of this study, a Specific Fuel Cost of $4.95/m/kWh in 2007 dollars will be used for all of the PWR NPPs.

General Electric did not provide fuelling cost data for either the ABWR or the ESBWR. Specific Fuel Cost tends to be slightly higher for BWRs than PWRs due to neutron absorption in the channels that surround the fuel assembly (see Appendix A). Similar to PWRs, large BWRs offer slightly better fuel economy than smaller units. BWR Specific Fuel Costs are historically approximately 4% higher than PWRs.

PWR and BWR fuel cost is widely variable world-wide, with typical fuel assembly costs in Japan being in the range of three (3) times the cost of identical fuel assemblies in the US. Fuel prices appear to be largely set by competition and market pressures.

AECL did not provide cost information on either the CANDU 6E or the ACR-1000. However, the Canadian Energy Research Institute (CERI) (ref. [2]) gives the Specific Fuel Cost of a twin CANDU 6 unit as $2.3/MWh in 2003 dollars. This is approximately $2.5/MWh in 2007 dollars, and is applicable to a single unit CANDU 6E, since the fuelling cost is independent of the number of units. CERI gives the ACR-700 (a smaller version of the ACR-1000) a Specific Fuel Cost of $4.0/MWh in 2003 dollars, or approximately $4.32M/kWh in 2007 dollars. The fuel cost for the ACR-1000 is expected to be approximately the same as for the ACR-700. There is more uncertainty associated with the ACR-1000 fuel cost than for other NPPs utilizing water cooled reactors, as ACR-1000 fuel has not been fabricated on a commercial basis.

Reliable information regarding the Specific Fuel Cost for HTGRs was not provided by the vendors. SLN estimates that the Specific Fuel Cost for HTGRs will be approximately 40% higher than for PWR and BWR plants. This is due to the higher enrichment requirements, and the cost of reactor grade graphite, which is estimated to be approximately $40/kg.

19.3.2 Back End Fuel Cycle Costs

The Back End fuel cycle costs cover the long term disposal cost of spent fuel. CERI indicates that the backend cost (spent fuel disposal) is $1.45/MWh in 2003 dollars, or approximately $1.57/MWh in 2007 dollars for both the CANDU 6 and the ACR-700. The volume of spent fuel on a per megawatt basis is a function of burn-up, where a CANDU 6E operating with a burn-up of 7500 MWd/tonne will generate approximately sic (6) times more volume of high level waste (fuel) than a PWR or BWR operating at 45,000 MWd/tonne burn-up. However, the total quantity of radioactive materials contained in the CANDU, PWR or BWR high level waste will be approximately the same. Hence, the specific back-end (spent fuel disposal) costs are not expected to vary significantly for the different considered NPPs that utilize water cooling. Hence, a back end cost of $1.57/MWh is adopted for all NPPs utilizing water cooling.

The US Department of Energy (DOE) (ref. [23] gives a backend cost of US$ 1/MWh. This is considered by some experts to be low.

Back end costs are anticipated to be higher for the HTGRs than for the NPPs utilizing water cooled reactors due to the amount of graphite that must be removed for disposal. Reliable information was not provided by the vendors. SLN estimates the back end cost for the HTGRs to be approximately $2.50/MWh.

19.3.3 Fuel Cycle Cost Summary

A summary of fuel costs is provided in Table 15.

Table 15, Summary of Fuel Cycle Costs for Ontario (2007 $m/kWh)

NPP Type	Description	Speciic Fuel Cost (front end Costs)	Specific Back End Fuel Costs	Specific Fuel Cycle Costs
ABWR	Single Unit	4.95	1.57	6.52
ACR-1000	Two Unit	4.32	1.57	5.89
	Single Unit	4.32	1.57	5.89
AP1000	Two Unit	4.95	1.57	6.52
	Single Unit	4.95	1.57	6.52
CANDU 6E	Twin Unit	2.50	1.57	4.07
	Single Unit	2.50	1.57	4.07
EPR	Single Unit	4.95	1.57	6.52
ESBWR	Single Unit	4.95	1.57	6.52
GA-HTGR	Four Unit	8.26	2.50	10.76
	Two Unit	8.26	2.50	10.76
PBMR	Four Unit	8.26	2.50	10.76
	Two Unit	8.26	2.50	10.76

19.4 Decommissioning Costs

An overview of decommissioning experience and costs is provided in Appendix L, which is taken from a briefing paper prepared by the Australian Uranium Institute (ref. [13]). In most countries including Canada, the nuclear power plant operator or Owner is responsible for the decommissioning costs.

The total cost of decommissioning is dependent on the sequence and timing of the various stages of the decommissioning program. Deferring the decommissioning of active areas of the nuclear island and thereby facilitating the decay of radioactive materials with a relatively short half life tends to reduce the total cost of decommissioning. However, in some circumstances this cost savings is offset by facilities maintenance and surveillance costs. The two nuclear plants undergoing decommissioning in Canada (Douglas Point in Ontario, and Gentilly 1 in Québec) have adopted the deferred decommissioning approach. Since both of these plants are within operating nuclear facility boundaries, they are not subject to additional security and surveillance costs.

Decommissioning costs contribute only a very small fraction to the total electricity generation costs. In the US, utilities are collecting between 0.1 and 0.2 cents/kWh to fund decommissioning. As of 2001, $23.7B of the total estimated cost of decommissioning for all US nuclear power plants had been collected, leaving a liability of approximately $11.6B to be covered over the lives of the 104 currently operating NPPs, based on DOE decommissioning cost estimates.

An OECD survey published in 2003 (ref. [6]) reported US dollar (2001) costs by NPP reactor type. Decommissioning costs for western PWRs were in the $200 to 500/kWe range. The decommissioning costs were in the $300 to 550/kWe range for BWRs, and in the $270 to 430/kWe range for CANDU NPPs. Decommissioning costs for NPPs that utilize gas cooled reactors were estimated to be much higher due to the greater amount of radioactive materials to be disposed of (particularly graphite), reaching $2600/kWe for some UK MAGNOX NPPs. However, the decommissioning of the Fort St. Vrain 330 MWe HTGR was completed for US$ 195M (approximately $600/kWe) and less than 1 cent/kWh despite its short 16-year operating life at relatively low capacity factors. Economy of scale applies to decommissioning, as there are more active materials per MW of capacity in smaller plants than in larger plants, and greater efficiencies are associated with the decommissioning of larger facilities.

Based on a review of the available information, an allowance of 0.2 cents/kWh is used to cover the decommissioning costs of NPPs that utilize water cooled reactors, and 0.3 cents/kWh is used to cover the decommissioning cost of HTGRs. The increased cost for decommissioning HTGRs results from the cost of graphite disposal.

20 Levelized Unit Energy Costs

The levelized unit energy costs for the NPPs considered in this evaluation are summarized in Table 16. The data in the table is generated by a simplified model, where the calculations are based on a five (5) year construction period, 30 year operating life, 5% discount rate, 100% debt financing through a term loan at an interest rate of 6%. The calculations do not include site acquisition costs, taxes or depreciation (either book or CCA). Levelized unit energy costs (due to the dominance of the capital investment) are strongly dependant on the input parameter that relates to the capital cost. The results in Table 16 should therefore be considered comparative rather than absolute. For further details on the SLN calculations, see Appendix U. For addition information, see Section 29.

Table 16, Levelized Unit Energy Costs (LUEC) Summary

Ref	Technology	Number of Units	LUEC[3]
1			
2	ABWR	Single	$76.17
3	ACR-1000	Twin	$69.51
4		Single	$81.20
5	AP1000	Twin	$71.01
6		Single	$80.10
7	CANDU 6E	Twin	$76.58
8		Single	$90.70
9	EPR	Single	$70.99
10	ESBWR	Single	$66.35
11	GA-HTGR	Four	$94.83
12		Two	$111.13
13	PBMR	Four	$95.10
14		Two	$111.45

[3] Costs are based on 100% debt financing, depreciation and taxes excluded

21 Water Processing Costs for SAGD Applications

21.1 Water Processing for SAGD Applications

21.1.1 Recovered Water Treatment Processes

The two (2) commercial water treatment options available for SAGD operations are HLS, and Evaporative. A recovered water de-oiling process is required and would precede both the HLS and Evaporative water treatment processes. A simplified schematic for a typical de-oiling system is shown in Figure 20.

a) The first process incorporates Hot Lime Softening (HLS), Anthracite filtration (after filters) and Weak Acid Cation (WAC) softening of the produced water. The HLS treated water is not high quality, but it can be used as boiler feedwater for 'once-through' Steam Generators (OTSG). The HLS process generates large quantities of sludge that is normally stored in sludge ponds. A simplified schematic diagram for an HLS system is shown in Figure 21. The water product from the HLS process must be demineralized before delivery to the NPP. Demineralization can be achieved with Reverse Osmosis (RO), or using alternate chemical treatment technologies.

b) The alternative process Evaporation for water treatment. The water treated by Evaporators is very high quality and can be used as boiler feed water to NPPs and to conventional fissile fired boilers. A simplified schematic for an evaporative water treatment system is shown in Figure 22.

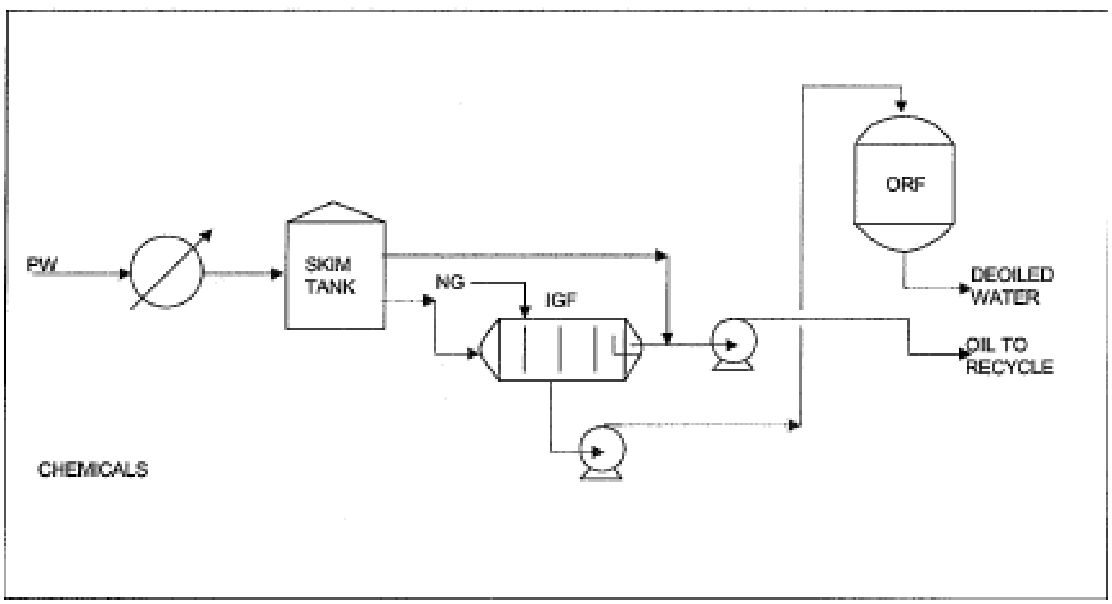


Figure 20, Simplified Schematic for Typical De-Oiling System

Although evaporators using water produced from a SAGD operation will meet the ASME limits given for power boilers, they are unlikely to meet the more stringent nuclear feedwater limits. To achieve the nuclear limits for feed water, the two main issues are ionic inorganics (including silica), and dissolved organic carbon, which together constitute the total dissolved solids (TDS). The current method of handling ionic inorganics is based on mixed bed resin polishing. An alternative method to this is electrodeionization (EDI). Organic carbon can be removed using an activated carbon bed, although speciality alternative ion exchange resins can also be used. Because the organics can foul the resin, the activated carbon is located upstream of the ion exchange columns.

Most of the organics from the evaporator are volatile, hence the potential for decreasing their concentration by altering the evaporator unit design.

All NPPs have full flow condensate polishing to assure feedwater quality. However, for providing 100% flow capability, the IX capacity of these systems is insufficient to process water from the evaporators such that additional capacity is required.

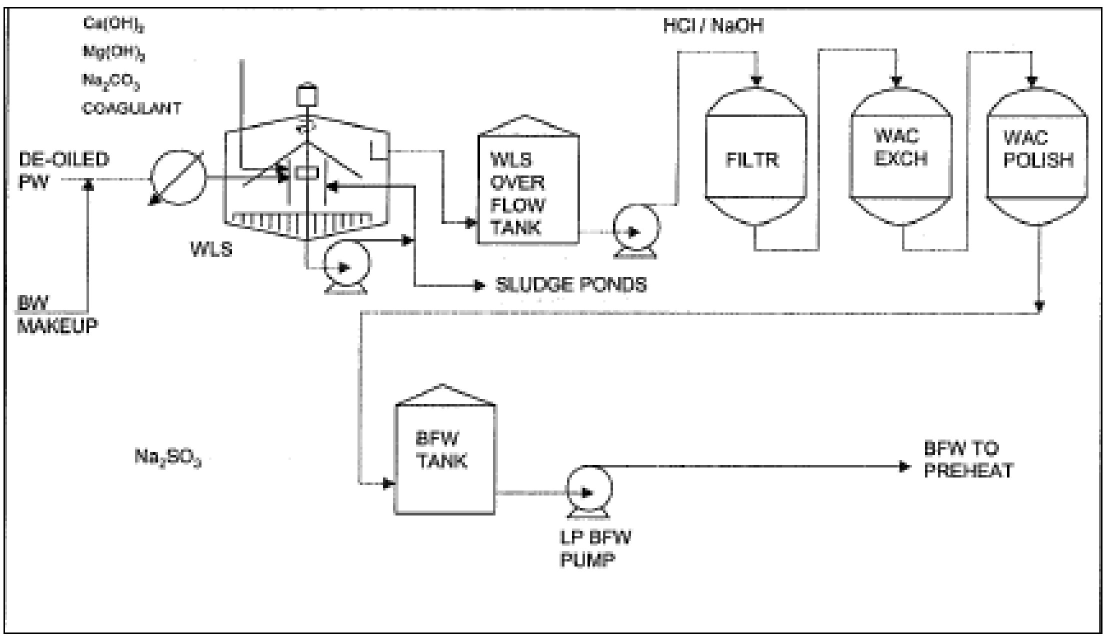


Figure 21, Simplified Schematic for Typical HLS Water Treatment System

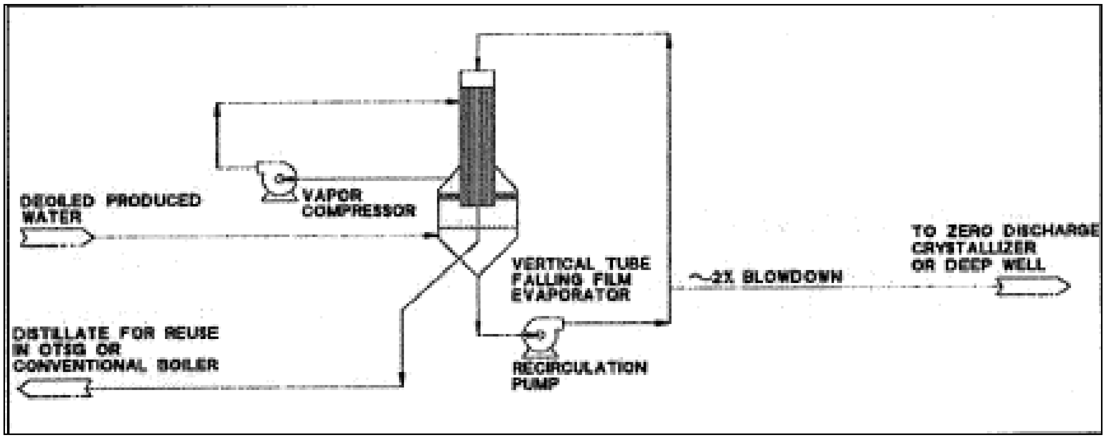


Figure 22, Simplified Schematic for Typical Evaporative Water Treatment System

A comparison of the two water treatment options is shown in Table 17.

Table 17, Comparison of HLS & Evaporative Water Treatment

Parameter	Conventional HLS Treatment	Evaporation
Operating History	Extensive	Limited
Plot Space / Building Requirements	Large area required	A small area is required
Steam Generation Alternatives	OTSG, Broach	OTSG, Broach, Power, Modified OTSG, NPP
Make-up Water	~15-45% of Produced Water Inflow	~15-20% of Produced Water Inflow
Sludge Disposal	~ 10,000 m^3/year	None
Disposal Water	~2-30% of Produced Water inflow	~0-2% of Produced Water inflow
Chemical Requirements	Lime, Magox, Acid, Caustic, Coagulant Aid, Oxygen Scavenger	Anti-scalant, Anti-foam, caustic if high pH operation and $CaSO_4$, Acid for seeded slurry operation
Energy Consumption	Relatively Low	High (20 kwh per m^3 distillate)
Ion Exchange Regeneration Waste	Neutralized WAC Regenerator waste	None
Organics (TOC) Removal	Slight reduction (~10%) through HLS	Virtually complete removal
Feedwater Chemistry	Greater limitations	More flexibility
Dissolved Organics Limitations	Approx. 300 mg/l	Can handle higher organics levels
Inlet TDS Limitations	Approx. 8000 mg/l	No limitations

21.1.2 Costs for Water Treatment (SAGD)

A total of 75,000 barrels per day (bpd) or approximately 2200 gpm of water equivalent of 100% quality steam is required for 30,000 bpd SAGD production with an SOR of 2.5. Between 90% and 95% of the water will be recycled and treated together with the make-up water.

The costs of delivering the recovered water from the bitumen processing facility to the water recovery facility, and the cost of delivering the treated water from the recovery facility to the NPPs is not included in this cost evaluation, as these costs are expected to be largely independent of the water treatment processes employed. In addition, these costs are dependant on the relative locations of the facilities. In general, the activities within the security area of a NPP should be minimized as all staff entering the security area must pass through security, and all vehicles entering the security are subject to searches.

21.1.3 Evaporative Treatment Option Costs

Capital Cost of Evaporators: Two (2) 1100 gpm evaporator units are required to treat the water that is fed to the NPP condensate polishing system. The related costs are as follows.

- Equipment Cost: Approximately $20M for each unit;
- Installation Cost: Approximately $10M for each unit.

The total estimated installed cost for the two (2) units is approximately $60M.

Operating Cost of Evaporator: The related costs are as follows.

- Electricity (20 kWh per cubic meter of distillate) Cost: $4.8M/year based on 0.055 $/kWh;
- Chemical Cost: Approximately $1.5M/year;
- Maintenance Cost: Approximately 2% of the equipment cost/year ($0.8M/yr.).

The total estimated O&M cost is approximately $6.6M/year.

Capital Cost of Additional IX Columns & Activated Carbon Filters: The related costs are as follows.

- Equipment Cost: $3M;
- Installation Cost: $1M.

Operating Cost for IX Columns and Activated Carbon Filters: The related costs are as follows.

- Malignance and Supplies: $0.8M.

The total estimated installed cost for the evaporative units and the additional IX capacity is approximately $64M.

The total estimated O&M cost for the evaporative units and the additional IX capacity is approximately $7.4M.

21.1.4 HLS Treatment Option Costs

Capital Cost for HLS Treatment: The related costs are as follows.

- HLS capital costs, including sludge handling: $40M;
- RO/EDI facility cost: $20M.

The total capital cost of HLS and RO facility is $60M.

Operating Cost for HLS: The related costs are as follows.

- Electricity Usage: Approximately $0.5M/year based on 0.055 $/kWh;
- Chemical Cost: Approximately $2M/year;
- HLS Maintenance Cost: at 2% of the equipment cost/year ($0.6M/yr.).
- RO/EDI system O&M and supplies: $0.9M.

The total estimated O&M cost is approximately $4.0M/year.

SAGD Water Treatment Summary: Although the CAPex and OPex of the Lime Softening / RO system may be less compared to the Evaporator/IX Columns, the Lime Softening / RO system is more labour intensive, requires more footprint area and generates approximately 20% waste (blowdown) that must be disposed of in comparison with 2-3% for the Evaporator/IX Columns. Make-up water requirements for the Evaporator/IX Columns will be significantly less, accordingly.

Utilizing evaporators in conjunction with additional IX capacity provides a better option for providing the water quality required for the NPPs.

21.1.5 Heating of Feedwater to the NPPs

The feedwater supplied to the steam generators of the NPPs must be heated to the reference temperature, which is typically 185^{o}C. The feedwater heating arrangement assumed in this study is shown in Figure 23. In this arrangement, live steam from the steam generators is used for feedwater heating. In NPPs dedicated to electricity production, feedwater heating is provided by extraction steam from the turbines. This steam is unavailable from NPPs that are largely dedicated to the delivery of steam for process applications.

Integration of the feedwater heating demand with the water recovery plant operations to take advantage of the available temperatures will serve to reduce the heat demand for feedwater heating. However, this study does not consider the integration of feedwater heating and water recovery plant operations, since this requires detailed knowledge of the relative locations of the plants and operational details for the water recovery plant. In general, the activities within the security area of a NPP should be minimized as all staff entering the security area must pass through security, and all vehicles entering the security are subject to searches.

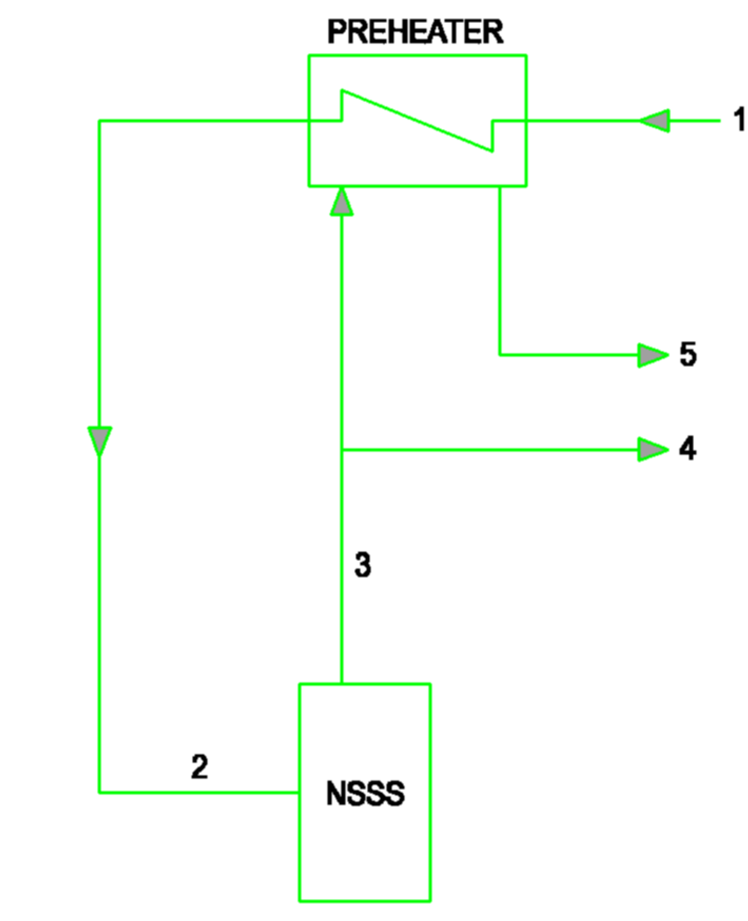


Figure 23, Simplified Feedwater Heating Arrangement

The energy utilized for feedwater heating based on the approach defined in Figure 23 is presented in Table 18 for AP1000 (Case 1) and the CANDU 6E (Case 2).

Table 18, Feedwater Heating Energy Requirements

Details	Temp °C	Pressure (MPa)	Enthalpy (kJ/kg) / (BTU/lb)
Case 1			
1 – Recovered water	25	~3.5	108 / 46.43
2 – Feedwater to NSSS	175	~6.0	745.98 / 320.73
3 – NSSS steam supply to preheater	273.2	5.8	2,786.8 / 1,198.2
4 – NSSS steam supply to application	273.2	5.8	2,786.8 / 1,198.2
5 – Preheater condensate	175	~5.5	743.4 / 319.6
Case 2			
1 – Recovered water	25	~3.0	107.55 / 46.24
2 – Feedwater to NSSS	175	~5.0	743.1 / 319.5
3 – NSSS steam supply to preheater	258.8	4.6	2,797 / 1,202.6
4 – NSSS steam supply to application	258.8	4.6	2,797 / 1,202.6
5 – Preheater condensate	175	~4.5	742.75 / 319.35

21.2 Treatment of Condensate

The condensate from the mining and integrated mining applications must be treated in a manner consistent with the NPP feedwater requirements. Although details of the chemistry and purity of the condensate return is not known, it is anticipated that technologies and costs for condensate treatment will be consistent with that of commercial water treatment facilities. These costs have not been addressed in this study.

Detailed implementation studies for NPP and mining and integrated mining scenarios should include methods of improving condensate quality through the design and operation of the mining and integrated mining facilities.

22 Risk Assessment

22.1 General

A comprehensive risk management plan is required in advance of a commitment to build a nuclear power plant.

The risk management plan must identify all potential project risks, and must define risk avoidance measures and risk mitigation measures. For a nuclear power plant project involving thousands of components and complex interfaces, this is a demanding task that requires detailed planning and scheduling. The utilization of proven technologies, proven components and systems, and contractors with proven track records on similar projects is an effective risk avoidance measure. Risk transfer and risk sharing is also common on major and complex projects, and this generally involves securing fixed price contracts with performance guarantees for a large portion of the project.

22.2 Risks Associated with Construction & Initial Operation

Since nuclear power plant in-place costs have been shown to be a function of construction schedule, the risk assessment must include a focus on factors that could cause schedule delays. These factors include, but are not limited to, weather related delays, licencing delays, component supply delays, labour shortages, labour unrest and work stoppages, technical problems, and construction problems. Each source of delay must be properly addressed. For example, a licencing delay can result from delays in the completion of a supporting research and development program.

Delays to the commissioning and ins-service schedule can also serve to substantially increase the in-place NPP costs due to interest and operations costs. The risk management plan, therefore, requires an in-depth evaluation of factors that could extend commissioning and delay the in-service date (e.g., discrepancies between measured and predicted reactor physics). A focus must also be placed on factors that could result in the NPP being taken out of service while problems are resolved (e.g., fuel performance).

There are other major risks related to plant performance. NPP outages and deratings can result from a range of factors that include, but are not limited to, equipment failures, substandard component performance, shortage of or inadequately trained operations and maintenance staff, and licencing issues.

Commissioning and operational risks are minimized by a focus on product provenness and product readiness. The latter requires a high percentage of the engineering and any required development programs to be completed prior to the start of construction.

22.3 Plant Security

The costs of implementing and maintaining NPP security can be significant, and can also be subject to substantial escalation. Security costs at nuclear power plants are determined by the requirements defined for the plant by the nuclear regulator. In the US, the NRC bases the security requirements on a design basis threat, which is the most demanding threat against which the plant must be designed and protected by way of physical security measures and/or employing security staff.

Specific information regarding the cost of security measures in Canada is difficult to obtain. This information is more readily available in the US: two examples are provided below.

a) PG&E estimates that it spent $15.5M in NRC-mandated security additions at Diablo Canyon in 2004 and that it will spend an additional $1M per year from 2006-2009 to meet NRC-mandated security requirements. PG&E also identified over $11M in other security-related capital expenditures that it will make between 2005 and 2009. PG&E did not identify security-related O&M expenditures (PG&E 2005b) (ref. [39]).

b) SCE estimated that SONGS would require capital expenditures of $69.9M in 2004 and 2005 and O&M expenditures of $4.5M in 2004 and $9.8M a year in 2005 and 2006 for physical changes to meet the NRC's design basis threat upgrade (SDG&E 2004, p.15) (ref. [40]). SCE explained that there "are no available sources of funding from the federal government or other outside entities for SCE to recover all or a portion of the increased security costs to comply with NRC security requirements resulting from the September 11, 2001 terrorist attack" (SCE 2005b) (ref. [41]).

The containment structure and its companion shield building (employed on all modern NPPs except the CANDU 6E and the ACR-1000) are designed to protect principal nuclear systems from the effects of an accidental aircraft crash. However, post 9-11, the possibility of intentional aircraft crashes employing aircraft laden with explosives has been identified. Although the NRC has completed studies assessing the potential repercussions of such an event, it has not released the findings of these studies. The future regulatory response by NRC and the other national regulators to this threat cannot be predicted. However, the potential exists for a significant increase in aircraft protection provisions for new nuclear power plants.

Cyber security, a relatively new area of concern for nuclear power plants, has been addressed by the NRC, providing US utilities with methodologies to perform cyber security self-assessments. The NRC is considering enacting a new law to protect nuclear power plant information and technology.

22.4 Uranium Price Cost & Supply Risks

Uranium prices have increased by more than a factor of 10 during the past five years, from approximately US$10 per pound of uranium oxide in December of 2001, to US$135 per pound of uranium oxide in June of 2007 (ref. [42], pg. 4, and [45]). Enrichment prices have also increased during the past five years, from US$99 per Separative Work Unit (SWU) for enrichment services in December 2001, to US$19 per SWU in 2007 June (ref. [43]). Approximately 80% of the uranium supplied in 2007 was supplied under the terms of long term contracts, and was therefore not subject to price escalation beyond that provided by the contract. Both Uranium and SWU prices have been very volatile over the past year.

The recent escalations in the price of uranium oxide and enrichment services have resulted from the increased number of NPPs in operation world-wide, from the increased capacity factors of the world nuclear fleet, and from underinvestment in mining and enrichment facilities. Given that ample uranium resources are available, the underlying question is whether or not the development of mines and the construction of enrichment facilities will keep pace with the demand. The uncertainty of future uranium oxide prices and enrichment costs must be included in the NPP risk assessment.

22.5 General Risk Factors

Additional risks are incurred by nuclear power plants as a result of the relatively long product schedule, which typically exceed 10 years. During this period, everything from governments and government regulations to market demands and commodity prices can change, and new technologies may emerge. These risks can be minimized by a short and secure construction schedule.

22.6 Risk Mitigation

While risk mitigation is essential to all major projects, the approach taken to risk mitigation varies widely. George Schaefer of General Electric Credit Corporation has provided his perspective on the implementation of risk mitigations, as follows (ref. [45], pg. 217).

> *"The basic tenet of any risk containment strategy is to identify, quantify, and allocate risks to the participant that can best assess and control them. For example, the engineering firm should guarantee the design of the project, the general contractor should absorb the construction risks, the equipment vendors should bear the risks for the equipment performance, the project operator should bear the O&M risks and the financier should absorb the risks of changes in the financial market. The host facility should be responsible for the consequences of changes in the operation of the specific facility."*

23 Fuel Cycle Considerations

23.1 Background

The fuel cycle utilized by nuclear power plants encompasses the front-end fuel manufacturing activities that include enrichment (if required) of the uranium feedstock, and manufacturing of the reactor fuel assemblies. The back-end of the fuel cycle consists of the storage and/or disposal activities related to the spent fuel that is discharged from the reactor.

23.2 Nuclear Power Plant Fuel Cycles

23.2.1 CANDU Fuel Cycle

All CANDU reactors supplied by Atomic Energy of Canada world-wide operate with a natural uranium fuel cycle. The uranium extracted from ore contains approximately 0.7% U^{235} (the fissile isotope of uranium), with the balance being U^{238}. The excellent neutron economy afforded by the heavy water (D_2O) reactor coolant and the moderator enable the operation of CANDU reactors using natural uranium fuel, and a range of other low fissile content fuel options, including the use of recovered uranium from PWR/BWR spent fuel reprocessing plants. India is utilizing thorium, which is a fertile material, to a limited extent in some of their CANDU style NPPs. Due to the low fissile content of this fuel, on-power refuelling is required to maintain the core reactivity. Approximately one (1) fuel channel is refuelled per day in a CANDU 6 NPP.

The low fissile content of the new fuel allows for manual handling, and eliminates concerns related to the criticality of new fuel, regardless of whether the storage configuration is within air or light water.

When removed from CANDU reactors, the spent fuel is stored in wet fuel bays (large light water filled swimming pool type structures) located at the NPP for periods of up to 10 years following its removal from the reactor. After a period of a few years, and as the spent fuel bay capacity is reached, the spent fuel (having a very low heat generation) is placed in leak tight titanium or stainless steel canisters and moved into dry storage. The dry storage facility consists of above grade concrete modules.

Due to the natural uranium fuel cycle, CANDU reactors generate approximately seven times more spent fuel volume than PWRs and BWRs. However, the fission process waste products that are retained by the CANDU fuel are approximately the same as the fuel from PWRs or BWRs with the same electrical output capacity.

The fissile content of spent fuel from CANDU reactors is very low, and currently does not justify reprocessing to recover the fissile content. Plans for the long term disposal of spent fuel in Canada are for deep burial of the spent fuel in stable geological sites. Although the disposal concept has passed the environmental hearing stage, no site has yet been selected, and no plans are currently in place to establish a long term disposal facility.

23.2.2 PWR & BWR Fuel Cycles

All PWR and BWR reactors that are supplied world-wide are by necessity operated with an enriched uranium fuel cycle. Relative to CANDU, the poor neutron economy of PWRs and BWRs that results from the use of light water (H2O) reactor coolant and moderator requires operation with uranium fuel that is enriched from 3.5% to 4% with U^{235}. The pressure vessel configurations of PWR and BWR reactors preclude on-power refuelling. During the 1960's through 1980's most PWRs and BWRs are refuelled annually, with approximately 1/3 of the core fuel load exchanged during each refuelling. In recent years, the refuelling cycle has been extended such that most plants are being refuelled every 18 months, and some every 24 months. As in the case of CANDU fuel, the uranium extracted from ore contains approximately 0.7% U^{235} (the fissile isotope of uranium), with the balance being U^{238}. The purified uranium is processed by enrichment plants that separate U^{235} from the U^{238} to produce feedstock for the fuel manufacturer with the specified enrichment level.

Burnable poisons (neutron absorbers) are added to the new PWR/BWR fuel in order to prevent excessive power levels when the new fuel is loaded into the reactor. Centrifuge enrichment technology is currently the dominant enrichment technology in the industry. Tailings from the enrichment plant retain approximately 0.15% of U^{235}. New PWR and BWR fuel, due to the enrichment level, cannot be handled manually and must be stored and transported in a manner that precludes criticality in the event that it is submerged in water. New fuel is shipped in borated (boron is a neutron absorber) steel containers, and the amount of new fuel stored at any location is limited.

Spent fuel removed from PWR and BWR reactors is stored in wet fuel bays located at the NPP for periods of up to 10 years following its removal from the reactor. The water used in the fuel bay is borated to preclude criticality of the fuel while in storage. In the US and some other countries, as the spent fuel bay capacity is reached, the spent fuel (which after a period of several years has a very low heat generation) is placed in leak-tight titanium or stainless steel canisters and moved into dry storage at the NPP site. The dry storage facility consists of above grade concrete modules.

The spent fuel removed from PWR and BWR reactors contains significant levels of fissile material (i.e., uranium and plutonium). For this reason, some countries including Great Britain, France and Japan are reprocessing most of the spent fuel from their PWRs and BWRs to remove the fissile material, which is then utilized for the production of new fuel (ref. [35]).

Some European countries have long term, high level waste facilities in service. The US plans to place the spent fuel from its reactors into long term storage at stable geological sites. The first of these sites is the Yucca Mountain Repository in the State of Nevada (see Figure 24), which is operated by the US Department of Energy (DOE). The DOE originally planned to begin accepting spent fuel at the Yucca Mountain Repository on or before January 31, 1998. However, the facility has been embroiled in political controversy for several years, which has resulted in many delays. Currently, the most optimistic opening date for the facility is September of 2020 (ref. [35]). A permanent, long term disposal facility in Canada would be capable of accepting CANDU, ACR-1000, PWR, and BWR spent fuel.

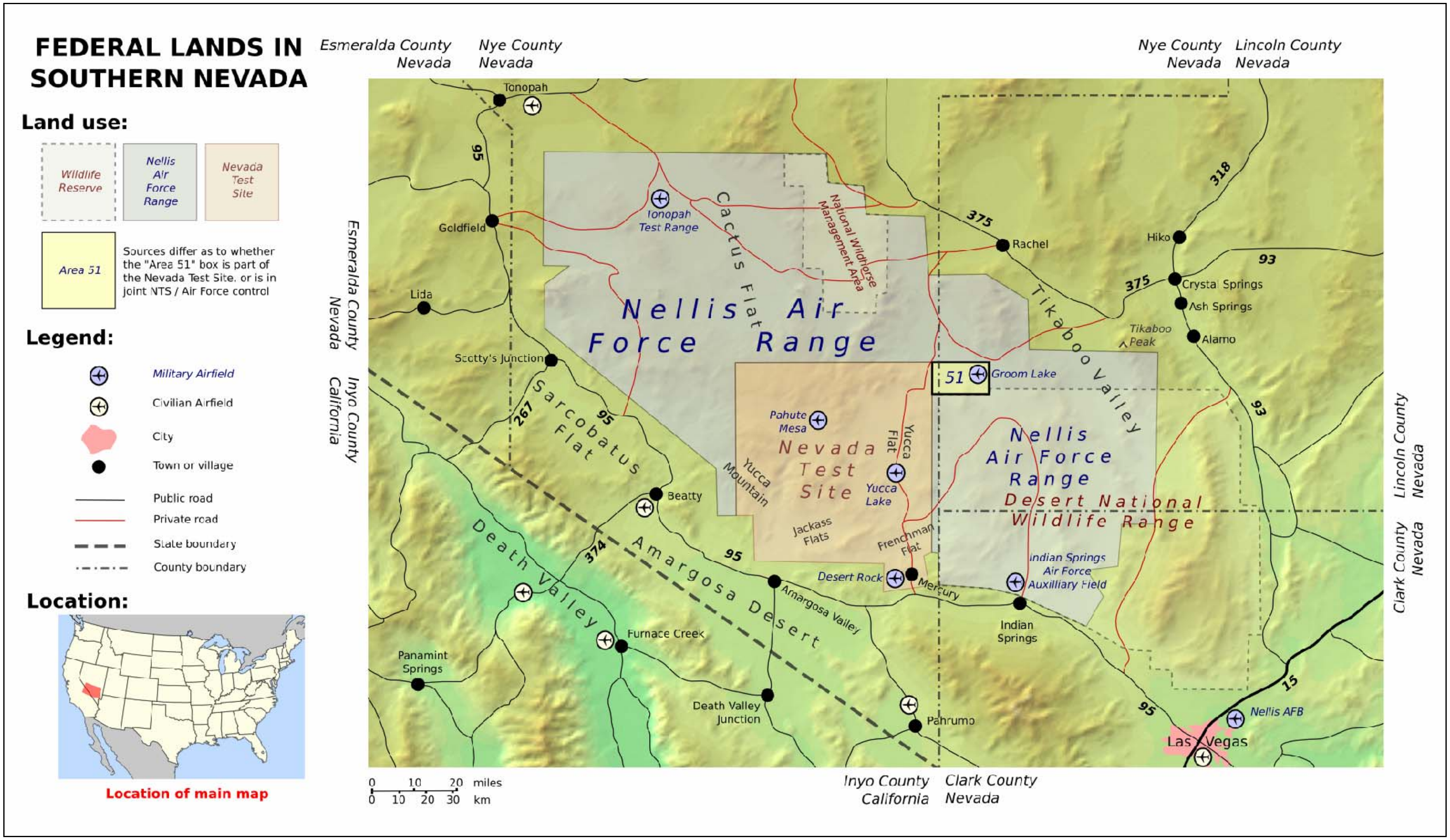


Figure 24, Location of Yucca Mountain Repository for Nuclear Spent Fuel (Nye County, Nevada)

23.2.3 ACR-1000 Fuel Cycle

The use of light water coolant, the incorporation of the neutron absorber Dysprosium into the ACR-1000 fuel, and a reduction in the heavy water moderator specific volume (required for reducing coolant void reactivity) has resulted in an enriched fuel cycle for the ACR-1000 that is similar to that of PWRs and BWRs. The ACR-1000's U^{235} enrichment level of approximately 2.7% is less than the level of PWRs and BWRs, which is between 3.5% and 4%. However, the process used to produce ACR-1000 fuel pellets is almost identical to the process used for producing PWR and BWR fuel pellets.

The U^{235} enrichment level of ACR-1000 fuel is sufficient to require the same new fuel handling methodologies as required for PWR and BWR new fuel.

Since ACR-1000 spent fuel has a low fissile material content relative to PWRs and BWRs (similar to CANDU fuel), the fissile content does not currently justify its reprocessing. The handling and disposal of ACR-1000 spent fuel will be the same as for CANDU reactors. On a per megawatt basis, the volume of spent fuel generated by the ACR-1000 will be approximately 2.5 times that of PWRs or BWRs.

23.2.4 HTGR Fuel Cycles

The HTGRs (GA-HTGR and PBMR) utilize an enriched uranium fuel cycle, with U^{235} enrichment levels in the range of 10%. Although the process used to manufacture TRISO fuel particles is unique to HTGRs, the process used for producing enriched uranium feedstock is the same for the ACR-1000, PWR and BWR reactors.

Due to the enrichment level, new HTGR fuel must be handled and stored in a manner that precludes criticality in the event that the fuel is submerged in water. Fuel volumes within a container are also limited by criticality concerns.

Following its removal from the reactor, the HTGR spent fuel is held in dry storage. Due to criticality concerns, its storage in light water is precluded, and measures must be taken to preclude criticality in the event that the fuel is submerged in water.

The volume of spent fuel generated by HTGRs is significantly higher than CANDU reactors on a per megawatt basis due to the high volume of graphite in the spent fuel (i.e., PBMR pebbles or the fuel blocks of the prismatic core GA-HTGR). General Atomics completed studies that demonstrate the feasibility of removing the fuel compacts from the prismatic blocks, and to recycle the blocks up to three times. This substantially reduces high level waste volumes (by approximately 95%) and reduces the cost of new fuel prismatic blocks. However, this process has not been demonstrated experimentally or commercially.

Spent fuel from HTGRs is compatible for long term storage and disposal in stable geological formations, and can be accommodated by such facilities as are provided for CANDU, ACR-10000, PWR, or BWR spent fuel.

24 Nuclear Options Evaluation Criteria

24.1 Evaluation Criteria Overview

The evaluation criteria discussed in the following sub-sections will be applied for assessing the viability of various nuclear power plant options for the Oil Sands applications. These criteria have been assigned a ranking range, where those of greatest importance relative to the Oil Sands applications are ranked as high, those of intermediate importance are ranked intermediate and those of lesser importance, including those that tend to differ little between the Nuclear Steam Plant (NSP) technologies, are ranked as low. Table 19 provides an overview of the relative merits of the nuclear energy options considered. For each Nuclear Steam Plant (NSP) considered, criteria with a high ranking are assigned a value between 0 and 40, those with an intermediate ranking a value between 0 and 10, and criteria with a low ranking a value between 0 and 5.

All uranium fuelled nuclear power plants produce plutonium during the fuel cycle, although some technologies produce more than others when operated according to design specifications. CANDU, for example, generates more plutonium than PWRs or BWRs. Weapons grade materials are can be produced with much greater efficiency and much lower cost in simple low pressure reactors designed for this purpose than in a commercial reactor designed for power production. Since all commercial reactors are subjected to IAEA safeguards that are directed at the detection of the diversion of nuclear materials, non-proliferation was not included in the evaluation criteria. There are also no anticipated differences in the security requirements for the NPPs considered.

24.2 Evaluation Criteria

24.3 Public Safety

The level of public safety afforded by a nuclear power plant is of primary importance. For this reason, safety is assigned a high ranking in the evaluations. All licencing jurisdictions, nuclear power plant vendors, and nuclear power plant operators world-wide enforce measures and procedures that ensure public safety with a very high degree of confidence. All nuclear power plant designs that are currently offered by the nuclear power plant vendors meet all international, country of origin, and client country safety requirements. Some of the latest nuclear power plant designs feature passive systems and/or characteristics that provide inherent safety. These plants are assigned slightly higher ratings in the evaluation.

24.4 NSP Capacity: Compatibility with Oil Sands Requirements

The Nuclear Steam Plant (NSP) must deliver quantities of electrical and thermal energy (steam) that are compatible with Oil Sands energy requirements, and must not exceed these requirements by an amount that cannot be readily utilized by the Alberta electricity grid or other users. Since the introduction of two (2) or more nuclear technologies into the Alberta Oil

Sands region is undesirable, the most favourable ratings will be assigned to NSP technologies that are capable of meeting all Oil Sands energy requirements. Capacity compatibility with Oil Sands requirements is ranked as having high importance.

24.5 NSP Energy Quality

The Nuclear Steam Plant (NSP) must deliver thermal energy (steam) at a pressure that meets Oil Sands energy requirements. As is the case with capacity (discussed above), the introduction of two (2) or more nuclear technologies into the Alberta Oil Sands region is undesirable. Hence, the most favourable rankings will be assigned to NSP technologies that are capable of meeting all Oil Sands energy requirements. The ratings assigned in Table 19 do not consider the use of steam compressors or electric boilers. The compatibility of energy quality with Oil Sands requirements is ranked as having high importance.

24.6 Licencing

Licencing is essential to the viability of any NSP being considered. Currently, there are no Nuclear Power Plants (NPPs) licenced for construction in Canada. Due to the importance of this factor, licencing is ranked as high. Nuclear power plant designs that are based on currently licenced plants in Canada will be given the highest rating. Plants that are licenced for operation or construction in other countries will be given a reduced rating, while the rating for plants that are determined to be licencable but not currently licenced will be further reduced.

24.7 Product Provenness & Market Readiness

Product provenness and market readiness is ranked as high importance, since this is critical to the near term application of nuclear power. NSPs that are currently in operation are given the highest ratings followed by those under construction, while products that will be or can be ready for construction within five (5) years will be assigned a lower rating. Products that are beyond the five year availability time frame will be assigned the lowest rating.

24.8 Specific Capital Cost

The capital cost of the NPP dominates the cost of energy generated by the NPP. Therefore, the in-place capital cost, including the cost of steam distribution to user locations, has a major impact and influence on the economics of the NPP for Oil Sands applications, and is ranked as having intermediate importance. Since steam is the dominate energy usage, the cost per MWth (Specific Capital Cost TH) will be the basis of evaluation.

24.9 Fuel Cycle Requirements

Fuel cycle costs, including those of new fuel supply and spent fuel disposal, impact on specific thermal energy costs. Since these costs are a small portion of the total energy production costs, fuel cycle requirements are ranked as having intermediate importance. Factors affecting new fuel cost include the enrichment level required, and the cost of fuel fabrication. Spent Fuel disposal and handling requirements are largely dependant on the spent fuel volume, since approximately the same quantity of fission products are produced by all thermal reactors based on the same thermal output.

24.10 Vendor Capability

Vender capability, which includes the ability to deliver a sound and reliable NPP design, and to construct and place a NPP into operation on schedule is of major importance for ensuring that project and construction schedules are met. For these reasons, this vendor capability is assigned an intermediate ranking. Vendors offering more than one NPP design may be ranked differently for each design. Vendors with strong technical and financial capabilities will be assigned the highest rating, while those with strong technical capability but weak financial capability will be assigned a lower rating.

24.11 Implementation Factors

The capability of the NSP to meet all Oil Sands energy requirements, and to accommodate staged expansion of plant operating capacity and multi-unit operation are significant for nuclear option implementation planning, for maintaining nuclear energy capacity that is consistent with Oil Sands energy demands, and for providing nuclear expansion flexibility. These capabilities are ranked as intermediate.

24.12 Operations & Maintenance Costs

The Operations and Maintenance (O&M) cost, based on the cost per MWth (Specific O&M TH), has a significant impact on the specific thermal energy cost. However, O&M costs are a relatively small portion of the total energy production costs and are therefore ranked as having low importance.

24.13 Operations & Maintenance Staff Requirements

Differences in the staffing level requirements and staff training requirements for the various NSPs considered will not have a significant impact on the Specific Energy Cost TH, and are therefore assigned a low ranking.

24.14 Operational Radioactive Releases

All nuclear power plants release radioactive materials to the environment during normal operation, which are small compared to the licencing release limits. For this reason, operational radioactive releases are ranked as low.

25 NSP Evaluation Summary

Table 19 covering the in-situ application, Table 20 covering the integrated mining application, and Table 21 covering the mining application all group the evaluation criteria under the assigned ranking discussed in the previous section. In Table 19, ratings for NSP energy Quality are given for the standard NSP and for the NSP utilizing steam compressors. These tables are not scientific and should not be used as a basis for NPP selection. It is also a snapshot in time. For example, the provenness rating for the AP1000 and EPR will increase to 10 once these plants are in service. The Evaluation Summary provides a general overview of the relative merits of the nuclear energy options. The acronyms used to identify the various reactors being considered are defined in the introductory pages of this report. These acronyms are widely used by vendors and in the nuclear industry. The ratings assigned to energy quality in Table 19 do not credit the use of electric boilers.

Table 19, NSP Evaluation Summary for In-Situ Application

Criteria	ACR-1000	ABWR	AP1000	CANDU 6E	EPR	ESBWR	GA HTGR	PBMR
High (0-40)								
Public Safety	36	37	38	36	37	38	40	40
NSP Capacity	25	20	25	30	15	15	38	35
NSP Energy Quality*	8/40	8/40	5/40	2/40	8/40	8/40	40	40
Licencing	25	30	30	36	28	25	15	15
Product Provenness & Market Readiness	10	38	35	35	20	15	5	5
Intermediate (0-10)								
Specific Capital Cost TH	9	8	10	7	9	10	4	3
Fuel Cycle Requirements	7	7	7	10	8	8	6	6
Vendor Capability	7	10	10	10	10	10	6	4
Implementation Factors	7	6	7	8	4	4	10	10
Low (0-5)								
Specific O&M Costs	4	4	5	3	4	5	3	3
Specific O&M Staff Requirements	4	4	5	3	4	5	4	4
Specific Operational Releases TH	3	4	4	3	5	5	4	4
Total	145/177	176/ 208	**181/216**	**183/221**	152/ 184	148/ 180	**181**	179

Note (for above table) *NSP without steam compressors / NSP with steam compressors

Table 20, NSP Evaluation Summary for the Integrated Mining Application

Criteria	ACR-1000	ABWR	AP1000	CANDU 6E	EPR	ESBWR	GA HTGR	PBMR
High (0-40)								
Public Safety	36	37	38	36	37	38	40	40
NSP Capacity	25	20	25	30	15	15	38	35
NSP Energy Quality	40	40	40	40	40	40	40	40
Licencing	25	30	30	36	28	25	15	15
Product Provenness & Market Readiness	10	38	35	35	20	15	5	5
Intermediate (0-10)								
Specific Capital Cost TH	9	8	10	7	9	10	4	3
Fuel Cycle Requirements	7	7	7	10	8	8	6	6
Vendor Capability	7	10	10	10	10	10	6	4
Implementation Factors	7	6	7	8	4	4	10	10
Low (0-5)								
Specific O&M Costs	4	4	5	3	4	5	3	3
Specific O&M Staff Requirements	4	4	5	3	4	5	4	4
Specific Operational Releases TH	3	4	4	3	5	5	4	4
Total	177	208	**216**	**221**	184	180	181	179

Table 21, NSP Evaluation Summary for the Mining Application

Criteria	ACR-1000	ABWR	AP1000	CANDU 6E	EPR	ESBWR	GA HTGR	PBMR
High (0-40)								
Public Safety	36	37	38	36	37	38	40	40
NSP Capacity	15	10	15	20	5	5	38	35
NSP Energy Quality	40	40	40	40	40	40	40	40
Licencing	25	30	30	36	28	25	15	15
Product Provenness & Market Readiness	10	38	35	35	20	15	5	5
Intermediate (0-10)								
Specific Capital Cost TH	9	8	10	7	9	10	4	3
Fuel Cycle Requirements	7	7	7	10	8	8	6	6
Vendor Capability	7	10	10	10	10	10	6	4
Implementation Factors	7	6	7	8	4	4	10	10
Low (0-5)								
Specific O&M Costs	4	4	5	3	4	5	3	3
Specific O&M Staff Requirements	4	4	5	3	4	5	4	4
Specific Operational Releases TH	3	4	4	3	5	5	4	4
Total	167	198	**206**	**211**	174	170	181	179

26 Nuclear Power Implementation Schedule

As discussed earlier, many steps are required to implement nuclear power for the Oil Sands applications. These steps include site selection, site qualification, environmental assessment, obtaining a construction licence, construction of the plant, training of the plant operating staff, obtaining an operating licence, and the commissioning and placing of the plant in service. If the NPP is a non-CANDU design, research and development efforts may be required to support the licencing application. In addition, a 'generic' or technology specific licencing process may be required in advance of the normal licencing process. The aggressive nuclear implementation schedule presented in Figure 25 shows the minimum period of thirteen and one-half years required from project commitment to in-service for a nuclear technology which has been implemented in other countries, but which is new to Canada. It may be possible to reduce the implementation schedule for the construction of the CANDU 6E to approximately 11 years, as shown in Figure 26. The implementation schedule for "first-of-a kind" NPPs such as the HTGRs and the ACR-1000 could take in excess of 15 years.

The schedule presented in Figure 25 shows that generic licencing and research and development activities (if required) are beginning at the same time as site selection, which is an optimistic scenario. A generic licencing phase will be required for any technology that is new to Canada, and will provide the CNSC with time to acquire staff and develop the necessary knowledge base for licencing a new technology in Canada. It is anticipated that research and development efforts would be limited for NPPs having completed rigorous licencing procedures in other countries, and would likely be greatest for technologies with a substantial degree of innovation relative to operating NPPs.

Repeat units at the same site, if constructed within the same time frame (not more than two years between construction starts) will avoid the time required for site selection, site qualification and environmental assessment. In addition, generic licencing and early licencing activities are avoided. The schedule for the repeat units at the same site is therefore set by procurement and construction activities.

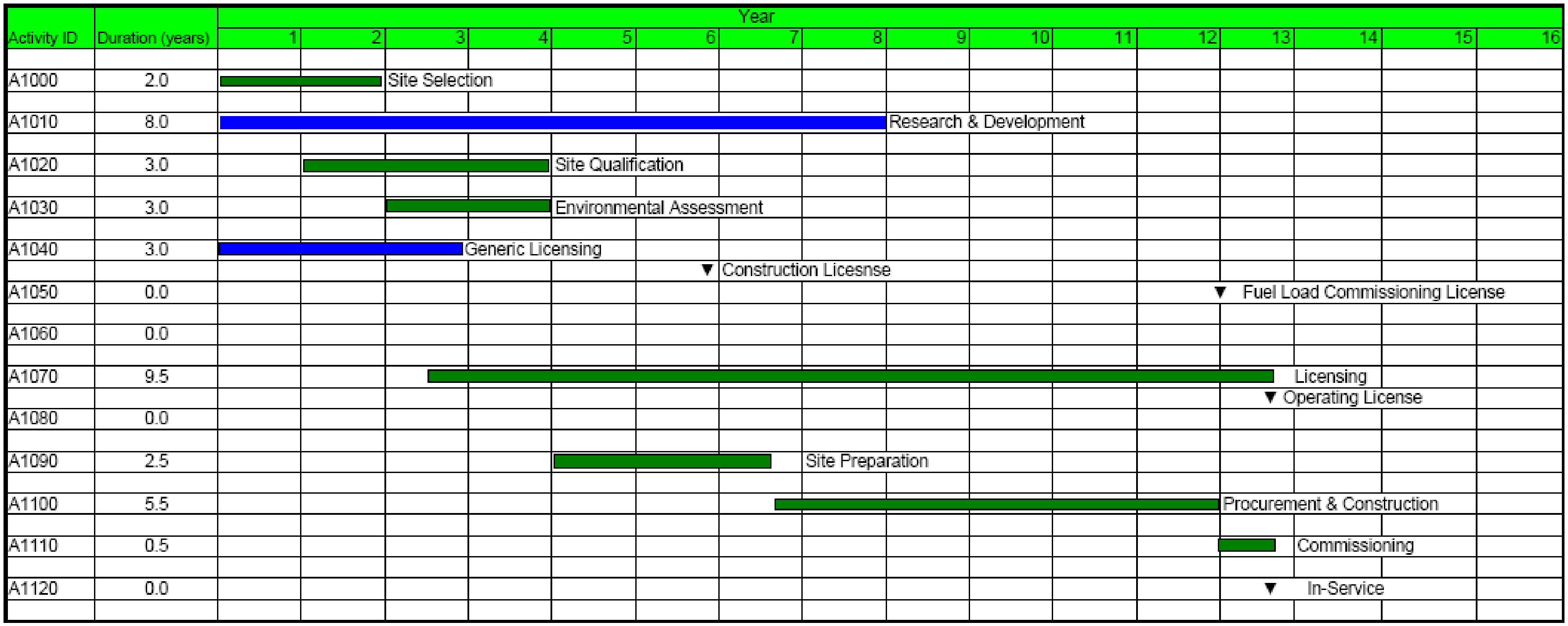


Figure 25, Generic PWR & BWR Implementation Schedule

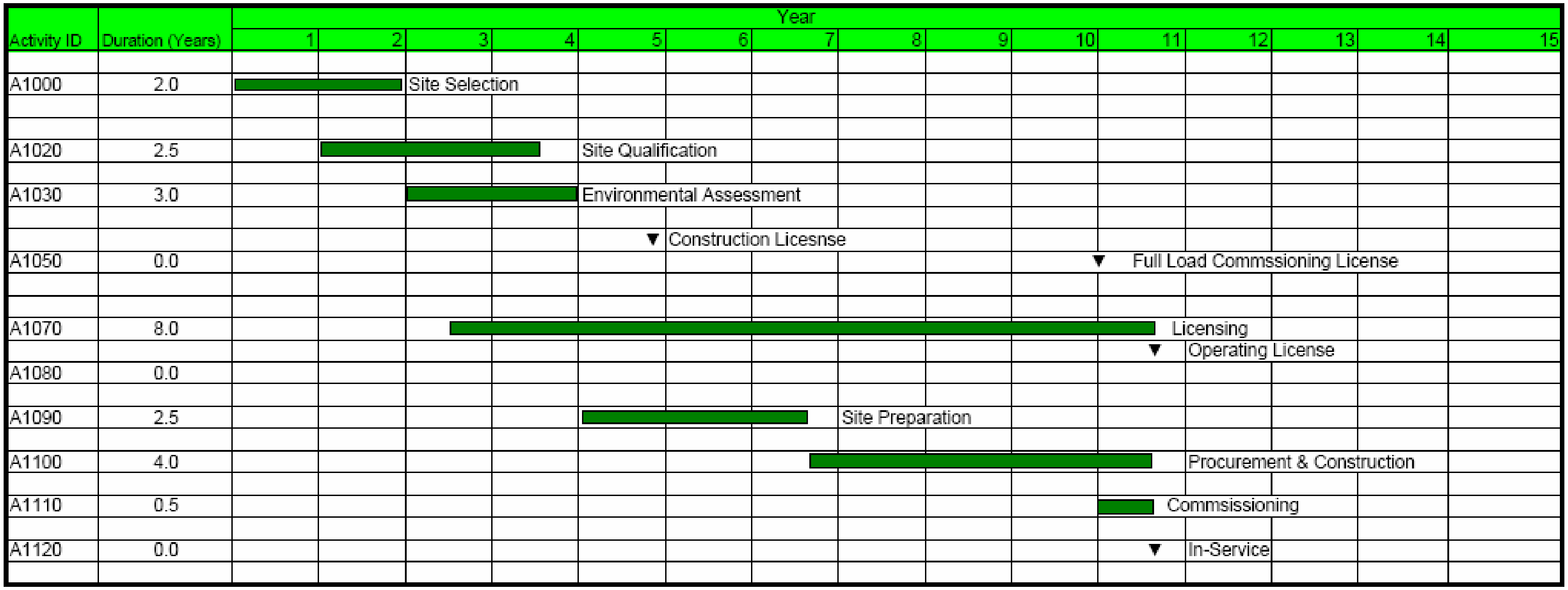


Figure 26, Potential CANDU 6E Project Implementation Schedule

27 Greenhouse Gas Emissions Reductions

27.1 Background

The Oil Sands industry is a major source of Greenhouse Gas (GHG) emissions, including CO_2, CH_4, and N_2O. In-situ Oil Sands extraction plants utilizing natural gas as fuel also emit NOx, Volatile Organic Compounds (VOCs), H_2S, CO, O_3, Polycyclic Aromatic Hydrocarbons (PAHs), and SO_2. In-situ production utilizing natural gas fuel yields approximately 60 kg of CO_2 emissions for every barrel produced (ref. [15]). This increases to approximately 80 kg per barrel if residue burning is utilized for the SAGD fuel.

A major advantage of nuclear power relative to fossil fuelled energy production is the substantial reductions in gaseous and solids emissions that are realized. A 3000 MWth nuclear power plant will avoid the emissions of approximately 10,000 tons of nitrogen oxides (NO_x), 32,000 tons of Sulphur Dioxide (SO_2), and over four million tons of CO_2 emissions every year. An overview of the potential CO_2 emission reductions for the representative reactors that are considered based on a first reactor in-service date of 2018 and estimates of Oil Sands developments is presented in Table 22 (reproduced from ref. [10]). Additional information is provided in reference [35].

The data presented in Table 22 adopts a simplistic approach, assuming that no greenhouse gas emissions are associated with nuclear power plants. In order to determine an accurate CO_2 emissions profile, each technology must be considered under site specific conditions, with all the life cycle activities evaluated. CO_2 emissions that are associated with the manufacture of components, the construction of the plant including transportation, the operation of the plant including the supply of spare parts, the disposal of all wastes, the fuel cycle, and the final decommissioning of the plant must all be assessed. For these assessments, it is reasonable to also include the CO_2 emissions associated with plant operating staff, including their transportation to and from the plant, and the activities associated with their off-work lifestyle. Using a simplistic example, the CO_2 emissions from a large diesel powered excavator in making an excavation are in the range of 5% to 10% of the CO_2 emissions of a crew of workers utilizing shovels and wheel barrows to make the same excavation. However, it may be argued that given the world population, and therefore the CO_2 emissions of the population are defined, the allocation of these emissions to specific projects is meaningless. Since coal-fired power plants operate with staff levels that are typically 1/3 those of nuclear power plants, including the CO_2 emissions associated with plant operating staff would serve to partially offset their CO_2 stack emissions.

Table 22, Potential CO_2 Emission Reductions

NPP	Application	Output	Annual GHG Reductions (metric tons CO_2 / year)	40 year GHG Reductions (metric tons CO_2)
2 PBMRs (500 MWth)	100,000 b/d SAGD	Steam and electricity	3.1×10^6	63×10^6
CANDU 6E	740 MWe	Electricity	2.2 X 106	86 X 106
ACR-1000 AP1000	1100 MWe	Electricity	3.2 X 106	129 X 106
EPR, ESBWR	1550 MWe	Electricity	4.5 X 106	180 X 106

Significant differences are expected to exist between the NPPs employing different technologies. CANDU NPPs, for example, have a relatively low energy utilization fuel cycle due to the use of natural uranium fuel. If the uranium from PWR/BWR spent fuel reprocessing plants is utilized in the fabrication of CANDU fuel, the CO_2 emissions associated with fuel production could actually be negative. PWRs, BWRs, and the ACR-1000 by comparison have a high energy consumption fuel cycle, since much of their fuel cost results from the energy required to enrich the uranium feedstock. Since the PWRs and BWRs utilize light water coolant and moderator, this water requires minimal energy to demineralise, while CANDU utilizes the heavy water moderator and coolant. The high cost associated with heavy water (currently in the $350/kg range) results from the cost of energy required to extract the Deuterium from the light water feedstock. The ACR-1000, with its light water coolant and heavy water moderator, falls approximately midway between the CANDU and the PWRs/BWRs in terms of the energy required to produce the coolant and moderator.

There are no internationally recognized ‘standard’ procedures that define scope or the approaches to life cycle CO_2 emissions audits. As a result, the methodologies employed vary widely, as do the analysis results. The references in Table 23 provide an overview of the approaches taken and proposed. Similarly, there is no internationally accepted standard for assessing the life cycle health and environmental impacts of electricity generating technologies. The references provided in Table 24 provide an overview of some of the approaches taken (ref. [35]).

Table 23, Lifecycle Analysis Methodology & Interpretation (ref. [35], Table 42)

Author	Title	Reference Information
AEA Technology Environment	Carbon Footprint of the Nuclear Fuel Cycle: Briefing note	Technical Report prepared for British Energy; London, UK, March 2006
Bergerson, Joule and Lave, Lester	A Life Cycle Analysis of Electricity Generation Technologies: Health and Environmental Implications of Alternative Fuels and Technologies	Carnegie Mellon Electricity Industry Center; November 2002
Budnitz, Robert and Holdren, John	Social and Environmental Costs of Energy Systems	Annual Review of Energy, 1 (1976) 553-580
Fthenakis, V.M. and Kim. H.C.	A Review of Risks in the Solar Electric Life-Cycle	Brookhaven National Laboratory, Conference Paper; October 2005
Holdren, John, et. al.	Risk of Renewable Energy Sources: A Critique of the Inhaber Report	Energy and Resources Group, University of California, Berkeley; Report No. ERG 79-3, June 1979
Holdren, John, Morris, Gregory and Mintzer, Irving	Environmental Aspects of Renewable Energy Resources	Annual Review of Energy, 5 (1980) 241-291
Kammen, Daniel and Pacca, Sergio	Assessing the Costs of Electricity	Annual Review of Environment and Resources, 29 (2004) 301-344
Sundqvist, Thomas and Söderholm, Patrik	Valuing the Environmental Impacts of Electricity Generation: A Critical Survey	Journal of Energy Literature, 8:2 (2002) 3-41
U.S. Congress, Office of Technology Assessment	Studies of the Environmental Costs of Electricity	OTA–ETI–134, Washington, DC: U.S. Government Printing Office, September 1994.

Table 24, Health & Environmental Impacts of Generation Technologies (ref. [35], Table 43)

Author	Title	Reference Information
AEA Technology Environment	Generation and the Environment – a UK Perspective	Report prepared as part of the ExternE Project for the European Commission DGXII, June 1998
Bodansky, David	Electricity Generation Choices for the Near Term	Science, 207 (1980) 721-728
Gagnon, Luc; Belanger, Camille and Uchiyama, Yohji	Life-cycle assessment of electricity generation options: The status of research in year 2001	Energy Policy, 30 (2002) 1267-1278
Hohenemser,C; Kates, V.M. and Slovic, P.	The Nature of Technological Hazard	Science, 220:4595 (1983) 378-384
Holdren, J.P; Morris, G. and Mintzer, I.	Environmental Aspects of Renewable Energy Sources	Annual Review of Energy, 5 (1980) 241-291
Inhaber, Herbert[152]	Risk with Energy from Conventional and Nonconventional Sources	Science, 203 (1979) 718-723
Krewitt, Wolfram, et. al.	Health Risks of Energy Systems	Risk Analysis, 18:4 (1998) 377-383
Nuclear Energy Agency/ OECD	Externalities and Energy Policy: The Life Cycle Analysis Approach	Workshop Proceedings; Paris, France, 15-16 November 2001
Oak Ridge National Laboratory and Resources For The Future	Estimating Externalities of Nuclear Fuel Cycles, Report No. 8 on the External Costs and Benefits of Fuel Cycles	Study By the U.S. Department of Energy and the Commission of European Communities; April 1995
Spadaro, J.V. and Rabl, A. Centre d'Energetique	External Costs of Energy: Application of the ExternE Methodology in France	Final Report; Paris, France, January 1998

[152] This study has been discredited. See (Science 1979a; ERG 1979; Science 1979b; Science 1979c) In addition, Atomic Energy Control Board of Canada (now the Canadian Nuclear Safety Commission), under whose auspices Inhaber conducted his research, ultimately withdrew support for his report, and they no longer list this report among their publications. See (CNSC 2005)

27.2 Estimates of GHG Emissions from Nuclear Lifecycle

A number of organizations have generated life cycle CO_2 emissions estimates for PWR and BWR NPPs. Estimating the front-end CO_2 emissions is a relatively simple exercise. However, estimating the back-end related emissions is more difficult due to variations in the back-end approaches, the lack of experience with long-term repository disposal, and the limited experience with nuclear power plant and enrichment plant decommissioning. Table 25 (reproduced from ref. [35]) provides a summary of the current estimates of GHG emissions from the nuclear lifecycle for PWRs and BWRs.

Table 25, Estimates of GHG Emissions from the Nuclear Lifecycle (ref. [35], Table 31)

Study Sponsor/ Author	Grams CO_2-eq per kWh	Lifecycle Stages	Lifecycle Assumptions
British Energy	Total: 5	Many elements of the lifecycle; Excludes construction and decommissioning of fuel fabrication, reprocessing and storage plants.	100 percent centrifuge enrichment; 40 year reactor lifetime; Models lifecycle of Torness nuclear power station (Scotland); Includes reprocessing
ExternE-UK (EU)	Total: 5 Front End: 5	Plant construction only	Based on average emissions per £ from input sectors
Fusion Technology Institute (University of Wisconsin, Madison)	Total: 15 Front End: 14	Mainly the front end of the lifecycle; Small amounts of emissions included for the back end	100 percent centrifuge enrichment; 40 year reactor lifetime
Argonne National Lab (GREET)	Total: 16 Front End: 16	Front end, excluding plant construction; Includes fuel transport, enrichment, conversion, and fabrication	75 percent centrifuge enrichment; Mix of fuels used to power nuclear lifecycle
Brookhaven National Lab	Baseline: 25 Best Case: 16 Worst Case: 55 Likely range: Total: 25-55[111] Front End: 20-48	Full lifecycle; Does not include environmental remediation of mine and reactor sites	Independent estimate of emissions from Yucca Mountain; Compilation of inputs from a variety of studies
Oko Institut	Total: 33	Front end and electricity transmission only	70 percent centrifuge enrichment
Storm van Leeuwen	Total: 90-140 Front End: ~45	Full lifecycle; Includes environmental remediation of mine and reactor sites	70 percent centrifuge enrichment; Oil used to power all stages of nuclear lifecycle; 24 full-year equivalent reactor lifetime
Oxford Research Group (van Leeuwen)	Currently 84-122, but projected to increase as high-purity ore is depleted	Full lifecycle	35 year reactor lifetime 85 percent average load factor 0.15 percent uranium ore grade Enrichment method not specified

Source: (AEA 1998; AEA 2005; Oko-Institut 2006; Energy Policy 2007; Storm and Smith 2006; Oxford Research Group 2007, p.41; White and Kulcinski 1999; Nuclear Technology 2006)

[111] The authors note that the best (16 g CO_2-eq per kWh) and baseline cases (~25 g CO_2-eq per kWh) likely underestimate emissions while the worst case (55 g CO_2-eq per kWh) likely overestimates emissions (Energy Policy 2007, p.2555).

27.3 Evaluation of CO_2 Emissions

When comparing the CO_2 emissions from alternate energy sources, it is important to base these on common assumptions, which can often be difficult. The following sample results from the available literature are provided for illustrative purposes (ref. [35], pg. 164).

a) A 2002 study by the Center for Global and Regional Environmental Research found the lifecycle emissions from coal fired generation to be 1,028 g CO_2-eq per kWh. This value includes emissions from coal mining, transport, combustion, and coal waste transport (ref. [36]);

b) A 2000 study from the National Renewable Energy Laboratory analyzed emissions from a combined cycle, natural gas power plant. The analysis included power plant operation, natural gas production and distribution, power plant and pipeline construction and decommissioning, and ammonia production and distribution. It concluded that the lifecycle emissions from a combined cycle natural gas plant total 499 g CO_2-eq per kWh (ref. [37]);

c) The NREL 2000 Brookhaven study cited above found the lifecycle GHG emissions from photovoltaic and nuclear lifecycles to be comparable, and both in the range of approximately 15-60 grams of CO_2-eq per kWh (ref. [38]). The authors noted that a 2003 external report showing photovoltaic installations emitting 180 grams of CO_2-eq per kWh was based on technologies from the late 1980s. This illustrates one of the difficulties in performing lifecycle assessments on new technologies that are still in stages of rapid transformation.

28 Nuclear Application to Oil Sands Scenarios

28.1 Overview

A summary of energy requirements for the mining, integrated, and in-situ scenarios considered is provided in Table 26. Single unit power stations are assumed for all water cooled NPPs (i.e., a three (3) module GA-HTGR station and four (4) module PBMR station are assumed). The information provided under the scenario heading consists of the total energy demand (steam and electricity), surplus NPP thermal power, and the electricity generated in excess of what is required by the application if that power is used for electricity production. The surplus electricity numbers are approximate, since each application requires an optimization of the thermodynamic cycle. The data provided in Table 26 for the in-situ scenario does not include the power required to drive the turbine steam compressors (see Section 10). However, the energy utilized to compress the steam is not included in the energy demand value. As discussed in Section 10, turbine steam compressors are not commercially available at the present time, but are considered as technically feasible.

Table 26, Energy Demand & Surplus Power

NPP	Description	Energy Required (Steam plus Electricity) MWth) / Surplus (MWth) / Surplus Electricity MWe		
	Capacity	Mining	Integrated	In-Situ
ABWR	3926	793 / 3133 / 1065	1535 / 2391 / 813	1631 / 2295 / 780
ACR-1000	3187	793 / 2394 / 814	1535 / 1652 / 562	1631 / 1556 / 529
AP1000	3060	793 / 2267 / 771	1535 / 1525 / 519	1631 / 1429 / 486
CANDU 6E	2080	793 / 1287 / 438	1535 / 545 / 185	1631 / 449 / 153
EPR	4500	793 / 3707 / 1260	1535 / 2965 / 1008	1631 / 2869 / 975
ESBWR	4500	793 / 3707 / 1260	1535 / 2965 / 1008	1631 / 2869 / 975
GA-HTGR (3 units)	1800	760 / 1040 / 416	1457 / 343 / 137	1607 / 193 / 77
PBMR (4 units)	1500	760 / 740 / 296	1457 / 43 / 17	1607 / (-107)

A thermodynamic efficiency of 34% has been assumed for water cooled reactors and 40% for HTGRs in determining the data provided in Table 26. Oil Sands scenario energy requirement details are provided in Table 1.

28.2 Nuclear Power Implementation Scenarios

28.2.1 NPP Implementation for In-Situ Applications

There is a wide range of implementation scenario options for the NPPs considered. The following sub-sections outline possible NPP implementation scenarios regarding in-situ applications for illustrative purposes. The GA-HTGR is used as the reference HTGR, and the CANDU 6E is used as the reference water cooled NPP.

GA-HTGR Implementation Plan for In-Situ Applications: The implementation plan is focused on application flexibility, the overall economics, and the potential for expansion of the nuclear power facility.

The GA-HTGR with an output of 600 MWth is adopted as the reference HTGR design. However, the implementation plan approach that targets the first HTGR nuclear power station in the Oil Sands region is applicable to both the GA-HTGR and the PBMR. The output values provided in this section can be adjusted based on the thermal output of the reactor.

Commercial steam generating HTGRs (Fort St. Vrain and THTR-300) have been constructed and operated, while a direct cycle or a cogeneration HTGR facility has not been constructed. Therefore, a steam generating version of the GA-HTGR is assessed.

The implementation plan illustrated in Figure 27 assumes three (3) GA-HTGRs with in-service dates that are one (1) year apart. The first phase of the in-situ project is assumed to start six (6) months after the in-service date of the first GA-HTGR in order to provide time for the resolution of possible operations problems with the GA-HTGR. For subsequent projects, the start-up date for the first phase of the in-situ project could coincide with the in-service date for the GA-HTGR. Figure 27 presents the energy demand of the application and the energy supplied by the GA-HTGRs over the three (3) year period following the in-service date of the first GA-HTGR.

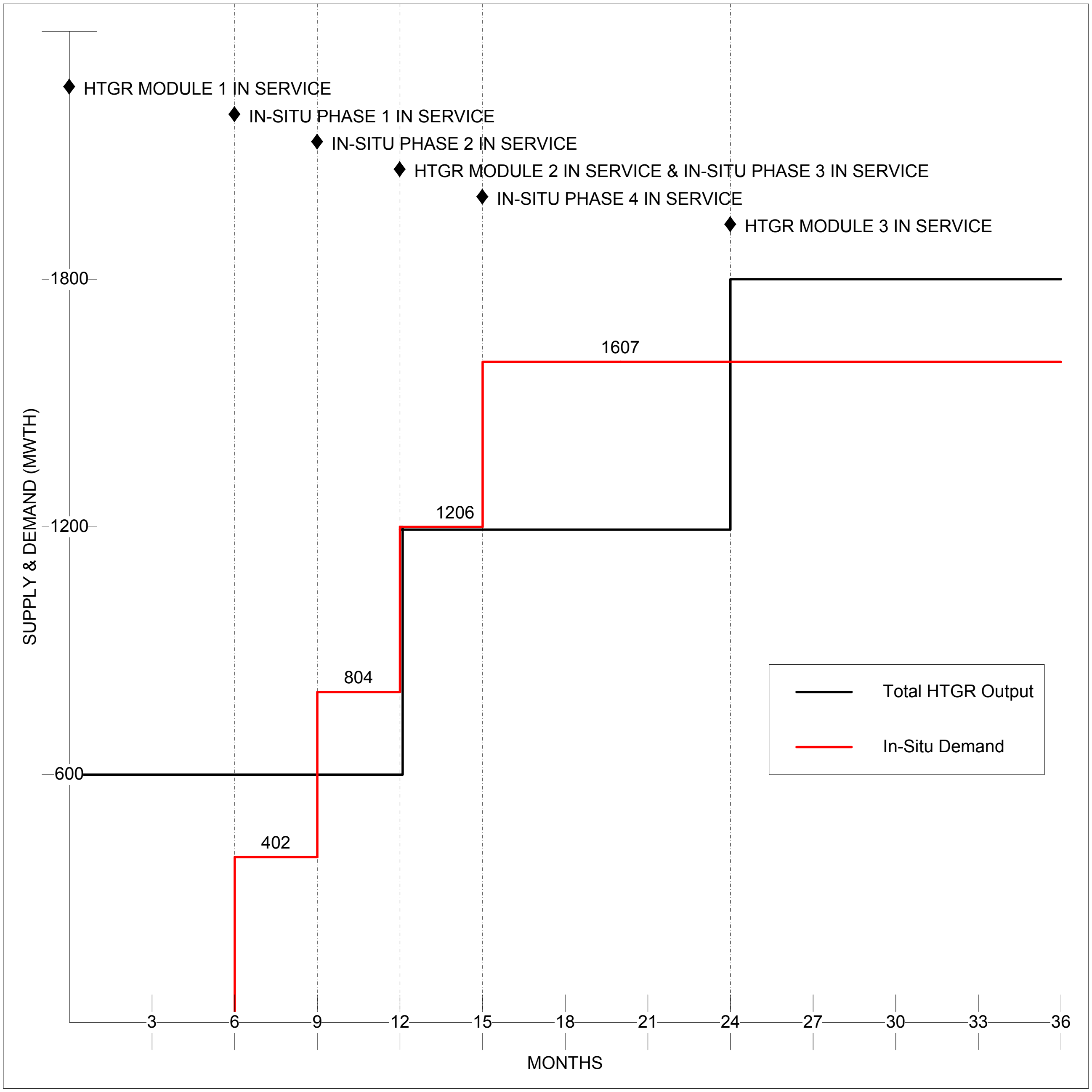


Figure 27, HTGR Implementation Plan Nuclear for In-Situ Applications

In the reference nuclear power plant station configuration shown in Figure 28, the GA-HTGR units deliver steam to a steam distribution header that supplies steam to in-situ Oil Sands applications, and to the steam turbine-generator facility located in a powerhouse adjacent to the NPPs. The reference powerhouse is designed to accept a maximum of 600 MWth of steam (optimization may lead to lower turbine-generator capacity being selected). An important cost factor is the steam turbine frame size employed. Steam supplies for additional in-situ and/or mining and upgrading applications and additional GA-HTGRs may be added as required to meet additional energy demands. In the future, when direct cycle HTGR technologies have been proven, cogeneration HTGR units can be considered.

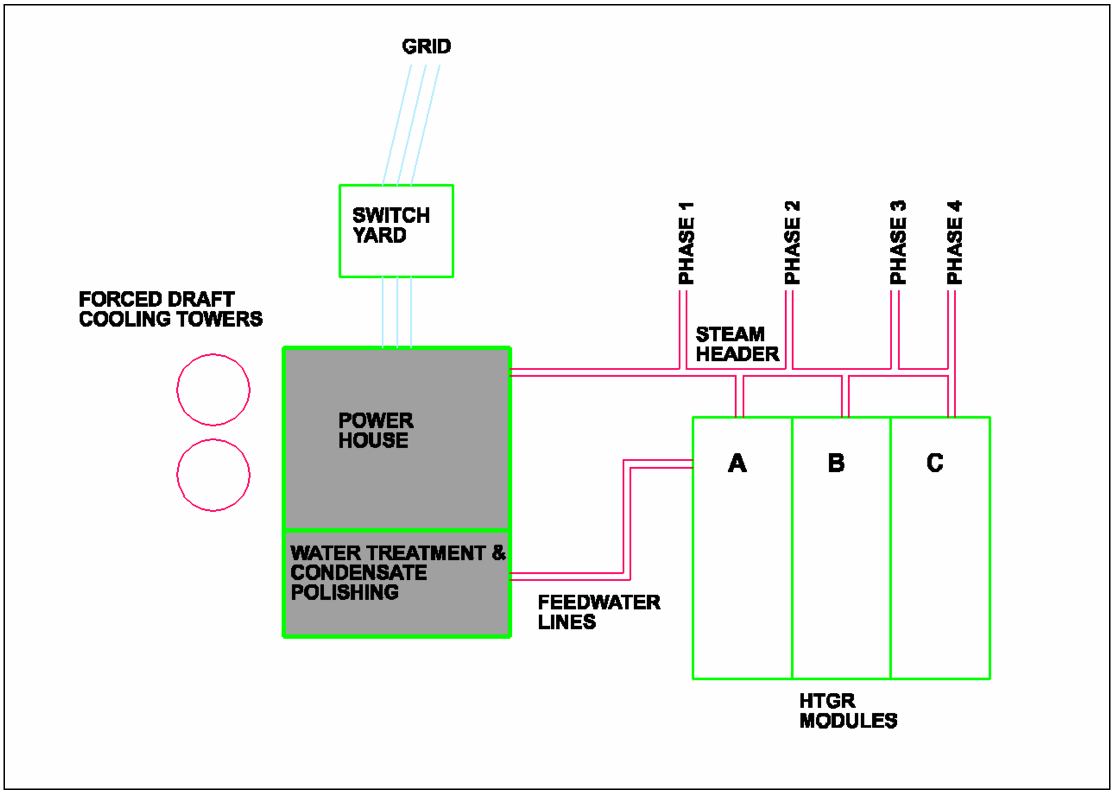


Figure 28, Potential HTGR Station Layout for In-Situ Applications

AP1000 Implementation Plan for In-Situ Applications: A potential configuration applicable to the AP1000 that provides cogeneration capability is shown in Section 10, Figure 16. In this configuration, the output of the AP1000 (3060 MWth) is distributed equally to six (6) identical drive turbines (510 MWth capacity each). In Figure 16, two (2) drive turbines are connected to generators, while the remaining four (4) are connected to steam compressors. Each generator delivers approximately 168 MWe for a total electrical output of 236 MWe, which results in approximately 200 MWe being available for electricity demands after allowance for Station loads. Since the in-situ application requires a total of 56 MWe, 144 MWe are surplus and be delivered to the Alberta grid or to other Oil Sands projects.

Each of the steam compressors provides approximately 408 MWth of steam at 12 MPa, which is consistent with the requirements specified for each phase of the reference in-situ application.

Start-up of the first phase of the in-situ application coincides with the in-service date for the AP1000 NPP. Hence, the AP1000 will operate at reduced power until such time as all four in-situ phases are in operation. Consideration should be given to adding a third generator module, which would generate electricity until such time as the steam was required by the in-situ project. In the long term, the redundant generator module could be retained as a back-up for the operating generator units and for facilitating maintenance of the generator modules, or could be moved to a new facility.

Additional operational flexibility and reductions in capital and O&M costs are achieved if a twin unit AP1000 is constructed, with the second unit serving another In-Situ project.

28.2.2 NPP Implementation for Integrated Mining Applications

GA-HTGR Implementation Plan for Integrated Mining Applications: The energy demands for the specified Integrated Mining application can be served by a three (3) module GA-HTGR station. The potential arrangement of the station is the same as for the in-situ project as illustrated in Figure 28. For the Integrated Mining scenario, the in-service dates for the first GA-HTGR and the integrated mining application should coincide, and an aggressive construction schedule with the minimum period between in-service dates for the three (3) GA-HTGR modules should be developed. The shortfall in energy supply to the Integrated Mining project that will exist until the final GA-HTGR module enters service will need to be made up by fissile fired energy supplies.

When all three (3) GA-HTGR modules are in operation, approximately 142 MWe of surplus power will be available for other Oil Sands applications and/or to supply to the Alberta grid.

Depending on steam distribution requirements, the use of steam de-superheaters should be considered.

CANDU 6E Implementation Plan for Integrated Mining Applications: The energy demands for the specified Integrated Mining application can be met by one (1) CANDU 6E NPP. The Integrated Mining application requires 1020 MWth as steam, leaving 1060 MWth of steam for electricity production. The total amount of electricity generated will be approximately 360 MWe, leaving 130 MWe available for other Oil Sands projects and/or to supply to the Alberta grid after allowance for Station loads and the supply of 175 MWe to the Integrated Mining Application.

A possible configuration of the electrical generation equipment consists of two (2) generator modules, with each accepting 530MWth as described in Section 10. Additional operational flexibility and reductions in capital and O&M costs can be achieved if a twin unit CANDU 6E is constructed, with the second unit serving another Integrated Mining project.

28.2.3 NPP Implementation for Mining Applications

GA-HTGR Implementation Plans for Mining Applications: A single GA-HTGR module with a capacity of 600MWth is capable of meeting the steam demand of the specified mining application (573 MWth). In this case, the electricity demand of 75 MWe would be supplied by the Alberta grid, or by alternate generation. The construction of four (4) GA-HTGR modules with a total output of 2400 MWth would provide steam to the three (3) mining projects and meet the electricity demand for these projects. The high steam pressure provided by the GA-HTGR can facilitate steam distribution to a number of mining projects.

CANDU 6E Implementation Plans for Mining Applications: The CANDU 6E, the lowest capacity NPP with a water cooled reactor, has a capacity of 2080 MWth. This far exceeds the demand of the specified mining scenario (793 MWth for steam and electricity). If steam is supplied to a single mining project (572 MWth), 1508 MWth will be available for electricity generation and/or other Oil Sands applications. If the steam is used for electricity production, approximately 512 MWe would be generated, leaving a surplus of approximately 382 MWe for supplying other Oil Sands projects and/or the Alberta Grid after station loads and the electrical demand for the mining application (75 MWe) are satisfied. Alternately, if the CANDU 6E provides steam to two (2) mining applications, approximately 318 MWe could be generated, leaving a surplus of approximately 307 MWe for supplying other Oil Sands projects and/or the Alberta Grid after Station loads and the electrical demand for the mining application (75 MWe) are satisfied.

28.3 Nuclear Power Plant Operations

The operation of nuclear power plants in compliance with all CNSC licencing basis requirements is a demanding task that is unique to NPPs. For this reason, an experienced private nuclear power operator would be best suited to manage nuclear power plant operations. Bruce Power is the only privately held nuclear operator in Canada. In contrast, all US nuclear plants are privately owned and operated, except for those owned by the Tennessee Valley Authority (TVA). However, many utilities with no prior nuclear power plant operating experience have been very successful nuclear power plant operators (e.g., Hydro Quebec and New Brunswick Power in Canada). Hence, an inexperienced nuclear operator should not be ruled out.

A Bruce Power announcement released in Peace River Alberta on November 29, 2007, indicated that Bruce Power had signed a letter of intent to buy certain assets from the Energy Alberta Corporation. This press release also indicted that Bruce Power Alberta intends to work with the Canadian Hydrogen Association to study the potential of converting electricity generated by nuclear units into hydrogen during off-peak hours.

29 Competitiveness of Nuclear Power

Natural gas fired Combined Cycle Gas Turbines (CCGT) and natural gas fired boilers are currently providing most of the electricity and steam generation requirements of the Oil Sands projects. If nuclear power is to be utilized in future Oil Sands projects, it must be economically competitive with the energy produced by natural gas combustion. The relative economics of nuclear power and natural gas facilities are dependant on many factors that include, but are not limited to capital, operations, facilities fuel costs, discount rates, interest rates, applicable Federal and Provincial taxes, investor return on equity, the plant life used in economic assessments, and the carbon or other taxes that may be applied to natural gas facilities.

The LUECs calculated by SLN for the NPPs considered, as summarized in Table 16, suggest that single Unit CANDU 6E and AP1000 NPPs are competitive with natural gas CCGT energy production at natural gas prices in the range of $6 per million BTUs.

MIT's economic comparison of CCGT plants with a number of nuclear plants is provided in Appendix S (ref. [10]). Although the capital costs associated with the MIT study considered nuclear plants are generally lower than those defined in this report, the MIT data can be readily adjusted, and the basis of MIT's economic analysis is reasonable. Based on the MIT information, a two (2) unit AP1000 nuclear power plant would be competitive with CCGT natural gas facilities and with gas prices in the range of $11 per million BTU. A two (2) unit CANDU 6E is competitive with CCGTs at natural gas prices in the range of $15 per million BTUs. The natural gas assessments assume that no carbon tax is applied.

The variation in the LUECs presented in Table 16 and in the MIT analysis is readily apparent. These differences result from the differences in analysis input variables, particularly the financial variables related to capital cost. For example, the MIT calculations:

a) Use a 50% debt/equity ratio, and (it appears) a 12.5% discount rate, which would be consistent with the equity component. The SLN model used 100% debt financing and a 'real rate' discount factor of 5% and an 8% interest rate during construction;

b) Use a six (6) year construction period versus five (5) years in the SLN model;

c) Use a 14.75% interest rate;

d) Use a 40 year term loan at 8% interest, whereas SLN used a 25 year term loan at 6%;

e) Include Federal and provincial taxes, which are excluded from the SLN calculation.

For example, the SLN model generated a LUEC of $76.85/MWh for the CANDU 6E utilizing the assumptions defined in Section 20. When the 14.75% interest rate during construction, 8% term loan, and 12.5% discount rate are substituted into the SLN model, the LUEC for the CANDU 6E is $122/MWh, which is close to that calculated by MIT ($132/MWh).

The above demonstrates that LUEC is very dependant on the financing assumptions utilized in the calculation. A more precise competitive analysis will be possible when the basis for the analysis is fully defined.

30 Conclusions & Recommendations

30.1 Study Specific Conclusions

The conclusions related to the specifics of this study are:

a) NPPs with water cooled reactors that are either currently available or will be available in near term:

1) Have thermal capacities greatly exceeding the energy requirements of the three (3) Oil Sands facility configurations considered in the study. For example, the output of the smallest capacity NPP with a water cooled reactor (the CANDU 6E) exceeds requirements for the mining, integrated mining and in-situ scenarios by approximately 1288 MWth/438 MWe, 544 MWth/185 MWe, and 450 MWth/153 MWe, respectively;

2) Produce steam at a lower pressure than acceptable for in-situ (SAGD) use.

b) High Temperature Gas Reactors (HTGRs) could meet the technical requirements for the three (3) scenarios considered, but are not currently commercialized. Among the considered technologies are the Pebble Bed Modular Reactor (PBMR), and the General Atomics High Temperature Gas Reactor (GA-HTGR). From 10 to 15 years may be needed before these designs are available for use in the Oil Sands region, assuming that a continuous and concerted effort is applied to their development;

c) The introduction of nuclear energy into the Oil Sands region will be a lengthy and expensive process. The Project duration, including site selection, environmental assessment, licencing and construction could span 11 years for the established CANDU 6E, and could take several years longer for technologies with no licencing experience in Canada;

d) Additional technical and economic information on the NPPs is unlikely to be obtained without issuing Requests for Proposals (RFPs).

30.1.1 Nuclear Power Plant Specific Conclusions

Conclusions which are NPP specific with respect to the application of nuclear energy in the Oil Sands region are:

a) The CANDU 6E can deliver power to the Oil Sands applications based on the current product status at least two (2) years earlier than any other NPP. Although more expensive to construct and operate than other NPPs utilizing water cooled reactors, the CANDU 6E has a proven performance basis and can serve all Oil Sands energy requirements with the employment of steam compressors and/or electric boilers;

b) The AP1000 is a modern, low cost water cooled reactor that will have operating experience prior to a construction commitment for an Oil Sands application. AP1000 units would take approximately two (2) years longer to place in service than the

CANDU 6E. The AP1000 can serve all Oil Sands energy requirements with the employment of steam compressors and/or electric boilers;

The larger NPPs with water cooled reactors (ABWR, EPR, and ESBWR) do not offer substantial specific capital costs, specific O&M costs, or capability relative to the twin unit AP1000 station, and due to their size are more difficult to accommodate in the Oil Sands region.

30.2 General Conclusions

General conclusions which can be drawn with respect to the application of nuclear energy in the Oil Sands region are:

1) Deployment of nuclear power in the Oil Sands region based on the currently available NPPs with water cooled reactors would require that surplus energy be converted to electricity and sold to the Alberta power grid, and/or transported as steam or electricity to other Oil Sands facilities. NPPs that are best suited for this purpose are those with the smallest capacities, and of these, the AECL CANDU 6E and the Westinghouse AP1000 represent the lowest risk options. The earliest deployment of nuclear energy in the Oil Sands region is estimated to be 2018;

2) Deployment of NPPs with water cooled reactors for the in-situ (SAGD) application would include steam compressors as an absolute requirement. Although technically feasible, steam compressors are not currently available, and a concerted effort in cooperation with vendors would be required for commercialization. A development period of approximately 50 months would be required to complete the design and testing of a prototype steam compressor. Steam compression would also be required to transport the steam produced over any significant distance;

3) The NPPs utilizing water cooled reactors are capable of meeting the mining and integrated mining applications, and are capable of meeting the in-situ application with the utilization of turbine steam compressors. Although not currently available, turbine steam compressors can be developed utilizing established technology within the project implementation schedule for NPPs;

4) The introduction of two (2) nuclear technologies in the Oil Sands region should not be ruled out (i.e., a water cooled reactor to meet demands over the next 15 to 20 years, supplemented by HTGRs to serve high pressure/temperature applications when they become available);

5) The most favourable nuclear plant economics can be achieved when a number of NPPs of the same design are constructed at one (1) location with in-service dates that are approximately one (1) year apart. An optimum number of NPPs at one (1) site in the Oil Sands region would likely range from two (2) for water cooled reactors, and from four (4) to six (6) for HTGRs.

30.3 Recommendations

The recommendations resulting from the study are:

a) If the issues identified above are resolved, nuclear energy could in principle make a substantial and long term contribution towards meeting future Oil Sands energy requirements, and reducing the environmental impact of Oil Sands projects. More detailed studies will be required to substantiate the practicality of nuclear energy use for these projects. In particular, a focus on HTGR technology implementation in the oil sands is warranted;

b) A practical way of utilizing the existing commercial NPP designs for use in the Oil Sands region would be to adopt a 'utility' approach for the delivery of energy (in the form of steam and electricity) to multiple Oil Sands facilities, and for providing electricity to the Alberta power grid. The licencing and operation of nuclear power plants is unique, and can best be achieved by a dedicated nuclear plant operator. This approach could achieve a higher optimization of the NPPs large thermal output, while addressing the complexity and uniqueness of NPP licencing and operation.

c) Due to the importance of the supply and distribution of steam produced by water cooled reactors to in-situ and mining applications, the assessment of steam compressors should be given a high priority. The most expedient route would be for PTAC to solicit proposals for the design, fabrication and performance testing of a demonstration turbine steam compressor. An invitation for proposals must be preceded by a study to determine technical requirements for the turbine steam compressors that include capacity and outlet steam pressure;

d) A further study that develops location specific implementation plans for the CANDU 6E and the AP1000 should be undertaken. This study could include a request for proposals to the vendors (AECL and Westinghouse).

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Attachment A: Calculations

The following representative calculations are provided to support the information contained in this report.

A-1: Energy Demand Calculations

Option #1:Mining Only

$$\dot{Q}_1 = \dot{m}_{H_2O,1} \cdot \left(h''_{@1MPa} - h'_{@25^\circ C}\right) \cdot \frac{1}{1000} + \frac{\dot{E}_1}{\eta_{th}} = (214.2) \cdot (2778 - 105) \cdot \frac{1}{1000} + \frac{75}{\eta_{th}} \quad [MWth]$$

$$for\ \eta_{th} = 0.34 \quad \Rightarrow \quad \dot{Q}_1 = 572.557 + 220.588 = 793.145 \quad [MWth]$$

$$for\ \eta_{th} = 0.40 \quad \Rightarrow \quad \dot{Q}_1 = 572.557 + 187.50 = 760.057 \quad [MWth]$$

Option #2: Integrated Mining

$$\dot{Q}_2 = \dot{m}_{H_2O,2} \cdot \left(h''_{@2.8MPa} - h'_{@25^\circ C}\right) \cdot \frac{1}{1000} + \frac{\dot{E}_2}{\eta_{th}} = (378) \cdot (2803 - 105) \cdot \frac{1}{1000} + \frac{175}{\eta_{th}} \quad [MWth]$$

$$for\ \eta_{th} = 0.34 \quad \Rightarrow \quad \dot{Q}_2 = 1019.844 + 514.706 = 1534.55 \quad [MWth]$$

$$for\ \eta_{th} = 0.40 \quad \Rightarrow \quad \dot{Q}_2 = 1019.844 + 437.5 = 1457.344 \quad [MWth]$$

Option #3: In-Situ (SAGD) @ 8.5 MPa

$$\dot{Q}_3 = \dot{m}_{H_2O,3} \cdot \left(h''_{@8.5MPa} - h'_{@25^\circ C}\right) \cdot \frac{1}{1000} + \frac{\dot{E}_3}{\eta_{th}} = (554.4) \cdot (2750.5 - 105) \cdot \frac{1}{1000} + \frac{56}{\eta_{th}} \quad [MWth]$$

$$for\ \eta_{th} = 0.34 \quad \Rightarrow \quad \dot{Q}_3 = 1466.665 + 164.706 = 1631.37 \quad [MWth]$$

A-2: Turbine Steam Compressor Performance Calculations

Since the live steam parameters for water cooled nuclear power plants (CANDU, ACR-1000, PWR or BWR) are typically in the range of 4 to 7 MPa (saturated condition), some steam compression would be required for the transport of process steam/heat to an Oil Sands site with the desired steam parameters (e.g., 8.5 MPa steam pressure). The main operating mode of these water cooled nuclear power plants is the stand-alone production of process heat/steam, and with all the NPP's mechanical power used to drive the steam compressor.

In any compression process, the fluid (in this case steam) that is being compressed becomes 'enriched' with energy and experiences an increase in enthalpy due to the increased pressure and temperature condition. The rise in temperature of a compressed fluid is lowest if the compression process is isentropic (at constant entropy). However, in practice the compression process is never ideal (adiabatic), which causes an increase in entropy. This imperfect adiabatic compression process is typically compared to the ideal isentropic process as a function of compression isentropic efficiency ($\eta_{is,com}$). In the case of steam compression, the assumed steam-compressor isentropic efficiency is 95% in all cases.

The mechanical power required to drive a steam compressor can be simply calculated as a product of the steam-compressor mass flow rate, M_{com} (kg/s) and the ideal (isentropic) compression-process enthalpy difference ($\Delta h_{comp,is}$ (kJ/kg)) divided by the steam-compressor isentropic efficiency ($\eta_{is,com}$), as follows:

$$P_{com} = \dot{M}_{com} \cdot \frac{\Delta h_{comp,is}}{\eta_{is,com}} = \dot{M}_{com} \cdot \frac{\left(h_{com,out-is} - h_{com,in}\right)}{\eta_{is,com}} \qquad [kW]$$

Therefore, $h_{com,out-is}$ (kJ/kg) is the steam-compressor outlet (discharge) enthalpy at ideal (isentropic) compression, and $h_{com,in}$ (kJ/kg) is the steam-compressor inlet enthalpy. Corresponding steam enthalpies at the steam-compressor discharge have been estimated from the superheated steam tables, taking into account the assumed steam-compressor isentropic efficiency of 95%.

Alternately, the required compressor power can be estimated using the following equation, assuming that steam is an ideal gas, and using the corresponding ratio of specific heats (κ=1.25-1.3 for steam), as follows:

$$P_{com} = \dot{M}_{com} \cdot C_{P,stean} \cdot \left(T_{com,out} - T_{com,in}\right) \quad [kW] \quad \Rightarrow$$

$$\Rightarrow \quad P_{com} = \dot{M}_{com} \cdot \left(\frac{\kappa}{\kappa - 1}\right) \cdot R_{stean} \cdot T_{com,in} \left[1 + \left(CPR^{\left(\frac{\kappa-1}{\kappa}\right)} - 1\right) \cdot \frac{1}{\eta_{is,com}}\right] \quad [kW]$$

Therefore, $T_{com,out}$ (K) is the real (adiabatic) steam-compressor outlet (discharge) temperature, $T_{com,in}$ (K) is the steam-compressor inlet temperature, $C_{P,steam}$ (kJ/kg*k) is the specific heat at a constant pressure for steam (typically approximately 2 kJ/kg*K), R_{steam} (kJ/kg*K) is the gas constant for steam (typically approximately 0.46 kJ/kg*K), and *CPR* is the compressor pressure ratio (ratio of compressor outlet and inlet pressures).

Since saturated steam typically exists at the nuclear reactor outlet, corresponding steam temperatures at the steam-compressor discharge (for different steam compressor discharge pressures) always fall well into the superheated steam region.

A-3: Steam Line Pressure Drop Calculations

A previously developed mathematical model (according to the relevant technical literature) was used for performing the calculations for estimating the pressure and temperature losses of superheated/saturated steam flowing along a steam pipeline, including the possibility of steam pipeline sizing.

This mathematical model was developed for optional, bi-directional thermal-hydraulic calculations: forward (in the direction of steam flow) and reverse or backward (in the direction opposite to steam flow). Either of these two (2) components of the mathematical model can be used for both the hydraulic and thermal calculations of superheated/saturated steam flowing through a pipeline, and as a repeatable (cyclic) iteration process for an arbitrary number of iterations.

The basic formula for estimating steam pressure drop is the well known Darcy's formula. In the case of forward thermal-hydraulic calculations, the basic formula is given as follows:

$$p_2 = p_1 - \left(f_{avg} \cdot \frac{L}{D_{in}} + \Sigma\zeta \right) \cdot \frac{\rho_{avg} \cdot W_{avg}^2}{2} \qquad [Pa]$$

Similarly, in the case of reverse thermal-hydraulic calculations, the basic pressure drop formula is given in the following form:

$$p_1 = p_2 + \left(f_{avg} \cdot \frac{L}{D_{in}} + \Sigma\zeta \right) \cdot \frac{\rho_{avg} \cdot W_{avg}^2}{2} \qquad [Pa]$$

In the above formulas, p_1 (bar) and p_2 (bar) are the static steam pressures at the pipeline inlet and outlet, respectively, L (km) is the pipeline/duct length; D_{in} (mm) is the pipeline inside 'hydraulic' diameter (equal to the real pipe diameter for circular pipes/ducts), λ_{avg} (-) is the average frictional coefficient along the pipeline/duct, $\Sigma\zeta$ (-) is the sum of local hydraulic losses (assumed/estimated), ρ_{avg} (kg/m^3) is steam density at the average steam temperature and pressure along the pipeline/duct, and W_{avg} (m/s) is the mean steam velocity at the average steam temperature and pressure along the pipeline/duct. It should be noted that in all Cases, the assumed pipeline wall thickness is 10 mm, and the assumed pipeline insulation thickness is 200 mm.

Alternately, Darcy's Formula can be rewritten as follows:

$$\Delta p = p_1 - p_2 = \left(1 + \lambda_{avg} \cdot \frac{L}{D_{in}} + \Sigma\zeta\right) \cdot \left(\frac{\rho_{avg} \cdot w_{avg}^{\ 2}}{2}\right) = \left(1 + \lambda_{avg} \cdot \frac{L}{D_{in}} + \Sigma\zeta\right) \cdot \left(\frac{\dot{M}^2}{2 \cdot A^2 \cdot \rho_{avg}}\right) \qquad [Pa]$$

Therefore, A (m^2) is the cross-sectional area of the pipe/duct, L (m) is pipe/duct length, and M (kg/s) is the steam mass flow rate through the pipeline/duct.

The above pressure drop equation can be applied to the entire pipeline/duct with some 'equivalent' diameter, or to all parts of the pipeline with different diameters and lengths. The total pressure drop can then be simply calculated as the sum of pressure losses in all parts of the entire pipeline/duct.

Since only the initial (pipeline inlet or outlet) steam parameters are known at the beginning, the final steam parameters are subsequently calculated during the iteration process. For the first iterative step, it is assumed that steam temperature remains the same along the entire pipeline. Then, using the corresponding average steam temperature (the same as initial/final steam temperature for the first iterative step), the thermodynamic (superheated steam enthalpy, saturation temperature at the given pressure, and saturated water and saturated vapor enthalpies) and physical (density, dynamic viscosity, specific heat, heat conductivity) steam properties at the average temperature are calculated using the suitable auxiliary equations derived from the steam tables. Although these auxiliary equations all contribute a certain degree of calculation error, using them provides much more realistic thermal-hydraulic calculations, since they are attempting to mathematically describe the variations of steam properties according to the thermodynamic steam table data.

With the steam properties calculated using average steam parameters, it is possible to determine the mean steam velocity (W_{avg}) and the average steam *Reynolds number* (Re_{avg}), respectively, as follows:

$$W_{avg} = \frac{4 \cdot \dot{M}}{\pi \cdot \rho_{avg} \cdot D_{in}^2} \quad [m/s] \quad \Rightarrow \quad \mathrm{Re}_{avg} = \frac{W_{avg} \cdot D_{in} \cdot \rho_{avg}}{\eta_{avg}}$$

Therefore, η_{avg} (Pa*s) is the mean steam dynamic viscosity at the average steam temperature, where π = 3.14159. For fluid flows with very high Reynolds numbers (Re) (for fully developed turbulent flow), the pipeline frictional coefficient (λ) depends only on the relative pipe roughness (ratio of absolute pipe roughness δ_a, in mm, and the pipeline hydraulic diameter, in mm). Assuming that the pipeline absolute roughness (δ_a) is approximately 0.50 mm for all Cases, it is possible to define the pipeline average frictional coefficient (f_{avg}) according to *Altshul's formula*, as follows:

$$f_{avg} = 0.11 \cdot \left(\frac{\delta_a}{D_{in}} + \frac{68.493}{\mathrm{Re}_{avg}} \right)^{0.25}$$

Thermal heat transfer calculations comprise estimates of radiation, convection and conduction (through insulation, if any) heat transfer heat losses along the pipeline. Heat losses due to radiation heat transfer from the insulation surface to the environment can be estimated according to *Stefan-Boltzman's law* of radiation, which determines the insulation-surface radiation heat transfer coefficient (h_{rad}), as follows:

$$h_{rad} = C_{rad} \cdot \frac{\left[\left(\frac{T_{surf} + 273.15}{100} \right)^4 - \left[\frac{T_0 + 273.15}{100} \right]^4 \right]}{\left(T_{surf} - T_0 \right)} \quad \left[\frac{W}{m^2 \cdot K} \right]$$

Therefore, T_0 (°C) is the environment temperature (assumed as -30°C in all Cases), T_{surf} (°C) is the mean insulation surface temperature (for the first iterative step assumed to be 5°C higher than the environment temperature), and C_{rad} = 5.7 (W/(m^2*K^4)) is the radiation constant of the black body.

Convective heat losses from the insulation surface to the environment can be estimated using the insulation-to-environment convection heat transfer coefficient ($h_{con,2}$) in the following way:

$$Free\ Convection\ \ (W_{wind} \le 1\, m/s) \quad \Rightarrow \quad h_{con,2} = (1.35)\cdot\left[\frac{(T_{surf} - T_0)}{D_{ins}}\right]^{0.25} \qquad \left[\frac{W}{m^2 \cdot K}\right]$$

$$Forced\ Convection\ \ (W_{wind} > 1\, m/s) \quad \Rightarrow \quad h_{con,2} = (4.13)\cdot\frac{W_{wind}^{\ 0.8}}{D_{ins}^{\ 0.8}} \qquad \left[\frac{W}{m^2 \cdot K}\right]$$

$$D_{ins} = D_{in} + 2\cdot\delta_{wall} + 2\cdot\delta_{ins} \qquad [mm]$$

In the above equations, W_{wind} (m/s) is the wind velocity (assumed 0 m/s), D_{ins} (mm) is the diameter of the pipeline with insulation, δ_{wall} (mm) is the pipeline wall thickness, and δ_{ins} (mm) is the pipeline insulation thickness.

Similarly, convective heat transfer from steam to the pipeline inner surface can be estimated using the steam-to-pipeline convection heat transfer coefficient ($h_{con,1}$) as follows:

$$h_{con.1} = (0.024)\cdot \mathrm{Re}_{avg}^{\ 0.8}\cdot \mathrm{Pr}_{avg}^{\ 0.45}\cdot\left(k_{s,avg}/D_{in}\right) \qquad \left[W/m^2\cdot K\right]$$

Therefore, $k_{s,avg}$ (W/(m*K)) is the mean heat conductivity coefficient at the average steam temperature, and Pr_{avg} (-) is the average steam *Prandtl number* at its average temperature, determined as follows:

$\mathrm{Pr}_{avg} = \dfrac{\eta_{avg}\cdot C_{p,avg}}{k_{s,avg}}$, where $C_{p,avg}$ (J/(kg*K)) is mean steam specific heat at its average temperature.

The total of linear heat losses from the pipeline surface to the environment can now be determined, as follows:

$$Ql_{tot} = \frac{(1+F_{local})\cdot\pi\cdot(T_{avg} - T_0)}{\left[\frac{\ln(D_{ex}/D_{in})}{(2\cdot k_{wall})} + \frac{1}{(h_{con,1}\cdot D_{in})} + \frac{1}{(h_{con,2}\cdot D_{ins})} + \frac{\ln(D_{ins}/D_{ex})}{(2\cdot k_{ins})} + \frac{1}{(h_{rad}\cdot D_{ins})}\right]} \qquad \left[\frac{W}{m}\right]$$

Therefore, T_{avg} (°C) is the steam average temperature, defined as the arithmetic mean of the steam temperatures between the pipeline inlet and outlet (T_1 (°C) and T_2 (°C), respectively), F_{local} (-) is the local heat losses fraction (which in practice is typically estimated at 20-30%, and here assumed to be 25%), D_{ex} (mm) is the pipeline outside (external) diameter (determined by definition as $D_{ex} = D_{in} + 2 * \delta_{wall}$), k_{wall} (W/(m*K)) is the heat conductivity coefficient of the pipeline wall material (typically steel) at the average wall temperature (where a high value is assumed to be ~52.3 W/(m*K) for steel), and k_{ins} (W/(m*K)) is the heat conductivity coefficient of the pipeline insulation material (typically mineral wool) at the average insulation temperature $T_{ins,avg}$ (°C), with parameters estimated as follows:

$$T_{ins,avg} = (T_1 + T_2 + 2 \cdot T_0)/4 \qquad (°C)$$

$$k_{ins} = 0.03316063 + 7.274223 \cdot 10^{-5} \cdot T_{ins,avg} + 3.976079 \cdot 10^{-7} \cdot T_{ins,avg}{}^{2} \qquad \left(\frac{W}{m \cdot K}\right)$$

For the next iteration step, a new value of the mean insulation surface temperature (T_{surf}) is then recalculated as follows:

$$T_{surf} = T_0 + \frac{Ql_{tot}}{\left[(1 + F_{local}) \cdot \pi \cdot D_{ins} \cdot (h_{con,2} + h_{rad})\right]} \qquad (°C)$$

Lastly, the final specific steam enthalpy (h_2 or h_1 (in kJ/kg)) and the corresponding temperature (T_2 or T_1) at the pipeline outlet or inlet, respectively, and depending if the thermal-hydraulic calculation is forwards or backwards can be estimated as follows:

$$h_2 = h_1 - \frac{Ql_{tot} \cdot L}{\dot{M}} \quad \left[\frac{kJ}{kg}\right] \quad \Rightarrow \quad T_2 = (T_1 + 273) \cdot \frac{h_2}{h_1} - 273 \quad [°C]$$

$$h_1 = h_2 + \frac{Ql_{tot} \cdot L}{\dot{M}} \quad \left[\frac{kJ}{kg}\right] \quad \Rightarrow \quad T_1 = (T_2 + 273) \cdot \frac{h_1}{h_2} - 273 \quad [°C]$$

The system of equations as explained above must then be recalculated for each of the chosen number of iterative steps. Also, the mathematical model is set to check and calculate the steam quality (unity in case of saturated or superheated steam) and to warn the user to adjust the input data in order to avoid the wet steam region.

The following tables contain the results from the steam line pressure drop calculations described above.

Table 27, Steam Line Pressure Drop Calculation Results (1.1 mm SAGD, ref. Figure 4)

30,0000 BPD SAGD; 1,093,750 lbs/hr Steam (SOR 2.5) - 20 inch							
Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.
0	12101	520	1.000	0	17101	540	1.000
629	11947	518	1.000	2018	16751	534	1.000
1257	11790	516	1.000	4037	16396	528	1.000
1886	11632	513	1.000	6055	16037	522	1.000
2515	11473	511	1.000	8073	15673	516	1.000
3144	11311	509	1.000	10091	15304	510	1.000
3772	11148	507	1.000	12110	14929	504	1.000
4401	10982	504	1.000	14128	14548	498	1.000
5030	10815	502	1.000	16146	14160	492	1.000
5659	10645	500	1.000	18165	13765	486	1.000
6287	10473	498	1.000	20183	13361	479	1.000
6916	10299	495	1.000	22201	12949	473	1.000
7545	10122	493	1.000	24219	12527	467	1.000
8174	9942	491	1.000	26238	12095	461	1.000
8802	9760	488	1.000	28256	11650	454	1.000
9431	9574	486	1.000	30274	11191	448	1.000
10060	9386	484	1.000	32293	10717	441	1.000
10689	9194	481	1.000	34311	10225	434	1.000
11317	8998	479	1.000	36329	9713	427	1.000
11946	8798	476	1.000	38347	9177	420	1.000
12575	8595	474	1.000	40366	8612	413	1.000

30,0000 BPD SAGD; 1,093,750 lbs/hr Steam (SOR 2.5) - 24 inch							
Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.
0	12101	520	1.000	0	17101	540	1.000
1894	11935	513	1.000	7790	16623	515	1.000
3787	11768	507	1.000	15580	16154	491	1.000
5681	11600	500	1.000	23370	15694	469	1.000
7574	11432	493	1.000	31160	15242	449	1.000
9468	11263	487	1.000	38951	14800	429	1.000
11361	11094	480	1.000	46741	14365	412	1.000
13255	10923	474	1.000	54531	13939	396	1.000
15148	10752	468	1.000	62321	13520	381	1.000
17042	10580	462	1.000	70111	13109	367	1.000
18936	10407	455	1.000	77901	12698	355	1.000
20829	10233	449	1.000	85691	12297	343	1.000
22723	10059	443	1.000	93481	11908	333	1.000
24616	9882	437	1.000	101271	11526	323	1.000
26510	9705	431	1.000	109062	11144	319	1.000
28403	9526	426	1.000	116852	10748	316	1.000
30297	9346	420	1.000	124642	10340	313	1.000
32190	9164	414	1.000	132432	9921	310	1.000
34084	8981	408	1.000	140222	9493	307	1.000
35978	8795	403	1.000	148012	9055	304	1.000
37871	8608	397	1.000	155802	8606	300	1.000

30,0000 BPD SAGD; 1,093,750 lbs/hr Steam (SOR 2.5) - 30 inch							
Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.
0	12101	520	1.000	0	17101	540	1.000
4130	11989	502	1.000	4464	17016	522	1.000
8259	11879	485	1.000	8929	16933	504	1.000
12389	11771	469	1.000	13393	16852	488	1.000
16518	11666	454	1.000	17858	16775	473	1.000
20648	11563	439	1.000	22322	16700	458	1.000
24778	11463	425	1.000	26786	16627	445	1.000
28907	11366	412	1.000	31251	16557	433	1.000
33037	11270	400	1.000	35715	16489	422	1.000
37167	11177	389	1.000	40179	16424	411	1.000
41296	11087	378	1.000	44644	16360	402	1.000
45426	10998	369	1.000	49108	16299	393	1.000
49555	10910	360	1.000	53573	16241	385	1.000
53685	10824	351	1.000	58037	16184	378	1.000
57815	10740	343	1.000	62501	16129	372	1.000
61944	10661	336	1.000	66966	16077	366	1.000
66074	10583	330	1.000	71430	16025	361	1.000
70204	10507	324	1.000	75894	15975	356	1.000
74333	10434	318	1.000	80359	15928	352	1.000
78463	10363	314	0.997	84823	15883	349	1.000
82592	10290	313	0.973	89288	15840	347	0.992
101320	9964	311	0.870	102501	15716	346	0.880
120317	9648	308	0.768	111043	15639	345	0.810
130871	9482	307	0.713	119585	15567	345	0.740
135093	9418	307	0.692	128126	15502	345	0.671
145647	9264	305	0.638	145210	15389	344	0.536
149869	9205	305	0.617	153752	15342	344	0.469

Table 28, Steam Line Pressure Drop Calculation Results (1.4 mm SAGD, ref. Figure 5)

30,0000 BPD SAGD; 1,400,000 lbs/hr Steam (SOR 3.2) - 20 inch							
Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.
0	12101	520	1.000	0	17101	540	1.000
380	11949	519	1.000	1179	16767	537	1.000
760	11794	517	1.000	2357	16426	533	1.000
1140	11638	516	1.000	3536	16080	530	1.000
1520	11479	514	1.000	4714	15728	526	1.000
1899	11319	513	1.000	5893	15369	522	1.000
2279	11157	511	1.000	7071	15004	519	1.000
2659	10992	510	1.000	8250	14630	515	1.000
3039	10825	509	1.000	9428	14249	511	1.000
3419	10656	507	1.000	10607	13858	507	1.000
3799	10484	506	1.000	11785	13458	504	1.000
4179	10310	504	1.000	12964	13047	500	1.000
4559	10132	502	1.000	14142	12624	496	1.000
4938	9952	501	1.000	15321	12188	491	1.000
5318	9769	499	1.000	16499	11738	487	1.000
5698	9582	498	1.000	17678	11272	483	1.000
6078	9392	496	1.000	18857	10787	478	1.000
6458	9198	494	1.000	20035	10282	474	1.000
6838	9000	493	1.000	21214	9752	469	1.000
7218	8798	491	1.000	22392	9194	464	1.000
7598	8591	489	1.000	23571	8601	459	1.000

30,0000 BPD SAGD; 1,400,000 lbs/hr Steam (SOR 3.2) - 24 inch							
Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.
0	12101	520	1.000	0	17101	540	1.000
1096	11944	517	1.000	3744	16722	530	1.000
2192	11785	513	1.000	7488	16341	519	1.000
3289	11624	510	1.000	11232	15958	509	1.000
4385	11462	506	1.000	14976	15572	499	1.000
5481	11299	503	1.000	18720	15183	489	1.000
6577	11134	499	1.000	22464	14792	480	1.000
7673	10967	496	1.000	26208	14396	470	1.000
8769	10799	493	1.000	29952	13997	461	1.000
9866	10629	489	1.000	33697	13594	451	1.000
10962	10457	486	1.000	37441	13185	442	1.000
12058	10282	482	1.000	41185	12771	433	1.000
13154	10106	479	1.000	44929	12351	424	1.000
14250	9928	475	1.000	48673	11923	415	1.000
15346	9747	472	1.000	52417	11487	406	1.000
16443	9563	468	1.000	56161	11041	397	1.000
17539	9377	465	1.000	59905	10585	388	1.000
18635	9188	461	1.000	63649	10116	379	1.000
19731	8995	458	1.000	67393	9633	370	1.000
20827	8800	454	1.000	71137	9133	361	1.000
21924	8601	451	1.000	74881	8605	351	1.000

30,0000 BPD SAGD; 1,400,000 lbs/hr Steam (SOR 3.2) - 30 inch							
Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.
0	12101	520	1.000	0	17101	540	1.000
4257	11911	505	1.000	5447	16931	522	1.000
8515	11722	491	1.000	10895	16764	505	1.000
12772	11536	477	1.000	16342	16602	489	1.000
17030	11351	463	1.000	21789	16444	474	1.000
21287	11168	450	1.000	27237	16290	460	1.000
25545	10987	438	1.000	32684	16140	446	1.000
29802	10808	426	1.000	38132	15994	434	1.000
34060	10630	415	1.000	43579	15852	422	1.000
38317	10454	404	1.000	49026	15714	411	1.000
42575	10280	393	1.000	54474	15580	401	1.000
46832	10107	383	1.000	59921	15450	392	1.000
51090	9936	374	1.000	65368	15323	384	1.000
55347	9766	365	1.000	70816	15200	376	1.000
59605	9594	356	1.000	76263	15081	369	1.000
63862	9425	348	1.000	81711	14965	362	1.000
68120	9257	340	1.000	87158	14851	357	1.000
72377	9093	332	1.000	92605	14741	351	1.000
76635	8930	325	1.000	98053	14634	346	1.000
80892	8769	318	1.000	103500	14532	342	1.000
85150	8608	312	1.000	108947	14433	339	0.992
				112290	14373	339	0.972
				119776	14237	338	0.926
				127262	14103	337	0.882
				134748	13971	336	0.839
				142234	13842	336	0.796
				149720	13716	335	0.754

Table 29, Steam Line Pressure Drop Calculation Results (1.7 mm Mining, ref. Figure 6)

100,000 BPD Mining; 1,700,000 lbs/hr Steam															
20 inch				24 inch				30 inch				36 inch			
Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.
0	5901	274	1.000	0	5901	274	1.000	0	5901	274	1.000	0	5901	274	1.000
157	5793	273	0.999	416	5798	273	0.999	969	5827	274	0.997	849	5876	274	0.997
314	5683	272	0.998	833	5694	272	0.997	1939	5750	273	0.994	1699	5849	274	0.994
471	5570	271	0.997	1249	5587	271	0.996	2908	5671	272	0.991	2548	5822	274	0.991
628	5456	269	0.996	1666	5478	270	0.994	3878	5589	271	0.988	3398	5795	273	0.988
784	5339	268	0.996	2082	5364	268	0.993	4847	5506	270	0.985	4247	5767	273	0.986
941	5219	267	0.995	2499	5246	267	0.992	5816	5421	269	0.983	5096	5739	273	0.983
1098	5096	265	0.994	2915	5124	265	0.990	6786	5334	268	0.980	5946	5711	272	0.980
1255	4970	264	0.993	3332	4996	264	0.989	7755	5244	267	0.977	6795	5682	272	0.977
1412	4840	262	0.992	3748	4864	262	0.988	8725	5153	266	0.974	7644	5654	272	0.974
1569	4706	260	0.992	4165	4727	260	0.986	9694	5059	265	0.972	8494	5625	271	0.971
1726	4565	258	0.991	4581	4584	259	0.985	10664	4963	263	0.969	9343	5596	271	0.969
1883	4419	256	0.990	4998	4435	257	0.984	11633	4864	262	0.966	10193	5567	271	0.966
2039	4266	254	0.990	5414	4279	254	0.983	12602	4763	261	0.964	11042	5538	270	0.963
2196	4106	252	0.989	5830	4116	252	0.982	13572	4660	260	0.961	11891	5508	270	0.960
2353	3938	249	0.989	6247	3945	250	0.981	14541	4554	258	0.959	12741	5479	270	0.957
2510	3760	247	0.988	6663	3764	247	0.980	15511	4445	257	0.956	13590	5449	269	0.955
2667	3572	244	0.988	7080	3571	244	0.979	16480	4333	255	0.954	14439	5420	269	0.952
2824	3371	240	0.987	7496	3366	240	0.979	17449	4218	254	0.952	15289	5390	269	0.949
2981	3156	237	0.987	7913	3145	236	0.978	18419	4100	252	0.950	20000	5222	267	0.934
3138	2921	232	0.987	8329	2904	232	0.978	19388	3978	250	0.947	27500	4945	263	0.911
3271	2704	228	0.988	8572	2753	229	0.978	22300	3583	244	0.941	32500	4755	261	0.896
3402	2470	223	0.988	8969	2482	224	0.978	26054	2990	234	0.935	37500	4558	258	0.882
3533	2208	217	0.989	9524	2036	213	0.980	28041	2619	226	0.933	42500	4356	255	0.868
3664	1908	210	0.991	9762	1807	207	0.981	30028	2178	217	0.932	45000	4251	254	0.861
3795	1549	200	0.993	10000	1541	200	0.983	32015	1593	201	0.935	47500	4145	252	0.855
3926	1107	184	0.999	10318	1106	184	0.989	33119	1101	184	0.941	50000	4037	251	0.848

Table 30, Steam Line Pressure Drop Calculation Results (3.0 mm Integrated Mining, ref. Figure 7)

100,000 BPD Integrated Mining; 3,000,000 lbs/hr Steam															
20 inch				24 inch				30 inch				36 inch			
Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.	Length, m	Press, kPa	Temp., °C	Vap. Frac.
0	5901	274	1.000	0	5901	274	1.000	0	5901	274	1.000	0	5901	274	1.000
52	5790	273	0.999	141	5793	273	0.999	426	5799	273	0.999	688	5837	274	0.998
104	5677	272	0.999	281	5683	272	0.998	852	5695	272	0.997	1376	5771	273	0.997
155	5562	271	0.998	422	5571	271	0.998	1277	5590	271	0.996	2064	5704	272	0.995
207	5444	269	0.997	563	5457	269	0.997	1703	5480	270	0.995	2752	5636	271	0.993
259	5324	268	0.996	704	5340	268	0.996	2129	5367	268	0.994	3440	5566	271	0.992
311	5200	266	0.996	844	5221	267	0.995	2555	5248	267	0.993	4128	5494	270	0.990
363	5074	265	0.995	985	5099	265	0.994	2981	5125	265	0.991	4816	5421	269	0.989
414	4944	263	0.994	1126	4973	264	0.994	3406	4998	264	0.990	5503	5347	268	0.987
466	4811	262	0.994	1266	4843	262	0.993	3832	4866	262	0.989	6191	5271	267	0.985
518	4674	260	0.993	1407	4707	260	0.992	4258	4728	260	0.988	6879	5194	266	0.984
570	4532	258	0.993	1548	4566	258	0.992	4684	4585	259	0.987	7567	5115	265	0.982
622	4386	256	0.992	1688	4420	256	0.991	5110	4436	257	0.986	8255	5034	264	0.981
674	4235	254	0.992	1829	4266	254	0.991	5535	4280	254	0.985	8943	4952	263	0.979
725	4076	251	0.991	1970	4105	252	0.990	5961	4116	252	0.984	9631	4869	262	0.978
777	3910	249	0.991	2111	3936	249	0.989	6387	3945	250	0.983	10319	4783	261	0.976
829	3735	246	0.991	2251	3758	247	0.989	6813	3763	247	0.983	11007	4696	260	0.975
881	3549	243	0.990	2392	3568	244	0.989	7238	3570	244	0.982	11695	4606	259	0.974
933	3351	240	0.990	2533	3367	240	0.988	7664	3364	240	0.981	12383	4515	258	0.972
984	3139	236	0.990	2673	3150	237	0.988	8090	3143	236	0.981	13071	4421	256	0.971
1036	2909	232	0.990	2814	2914	232	0.988	8516	2901	232	0.981	13759	4325	255	0.970
1107	2557	225	0.991	2975	2614	226	0.989	9048	2562	225	0.981	15900	4005	250	0.964
1132	2421	222	0.991	3150	2239	218	0.990	9568	2173	217	0.982	18550	3568	244	0.959
1156	2277	219	0.992	3325	1779	207	0.993	9984	1795	207	0.984	20022	3296	239	0.957
1181	2123	215	0.993	3442	1394	195	0.996	10088	1686	204	0.985	23850	2425	222	0.954
1205	1956	211	0.994	3471	1286	191	0.998	10296	1443	196	0.987	25028	2065	214	0.955
1230	1773	206	0.995	3500	1175	187	0.999	10400	1308	192	0.989	26500	1433	196	0.960