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Small Modular Reactors

Feasibility Study for Oil Sands Applications (SAGD Facility)

HATCH

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Acronyms and Abbreviations

AAAQO	Alberta Ambient Air Quality Objectives
ABWR	Advanced Boiling Water Reactor
ACO	Aboriginal Consultation Office
AEPA	Alberta Environment and Protected Areas
AER	Alberta Energy Regulator
AESO	Alberta Electric System Operator
AGR	Advance Gas-cooled Reactor
ARE	Aircraft Reactor Experiment
AUC	Alberta Utilities Commission
AVR	Arbeitsgemeinschaft Versuchsreaktor
BFW	Boiler Feed Water
BWR	Boiling Water Reactor
CAN	Canadian Nuclear Association
CAPEX	Capital Expenditure
CF	Capacity Factor
CMD	Commission Member Documents
CMNS	Central Mixedwood Natural Subregion
CNL	Canadian Nuclear Laboratory
CNSC	Canadian Nuclear Safety Commission
CSA	Canadian Standards Association
CSP	Concentrated Solar Power
CUC	Common User Considerations
DFO	Fisheries and Oceans Canada
DGR	Deep Geologic Repository
DNNP	Darlington New Nuclear Project
DOD	Department of Defense (U.S)
DOE	Department of Energy (U.S)
ECCC	Environment and Climate Change Canada
EIA	Environmental Impact Assessments
EPC	Engineering, Procurement and Construction
EPCM	Engineering, Procurement and Construction Management
EPEA	Environmental Protection and Enhancement Act
EPZ	Emergency Planning Zone
ESBWR	Economic Simplified Boiling Water Reactor

FAA	Fisheries Act Authorization
FNPA	First Nations Power Authority
FOAK	First Of A Kind
GE	General Electric
GHG	Green House Gasses
GoA	Government of Alberta
HRIA	Historical Resource Impact Assessment
HRMB	Historical Resources Management Branch
HRV	Historical Resource of Value
HTGR	High Temperature Gas Reactor
HTSA	Heat Transfer Surface Area
IAA	Impact Assessment Act
IAAC	Impact Assessment Agency of Canada
IAEA	International Atomic Energy Agency
IMSR	Integral Molten Salt Reactor
INL	Idaho National Laboratory
IPWR	Integral Pressurized Water Reactor
IPyC	Inner Pyrolytic Carbon
KEPCO	Korea Electric Power Corporation
KP-FHR	Kairos Power Fluoride salt-cooled high-temperature reactor
LARP	Lower Athabasca Regional Plan
LCOE	Levelized Cost of Electricity
LEU	Low Enriched Uranium
LFR	Lead Fast Reactor
LMFR	Liquid Metal Fast Reactors
LOCA	Large Loss of Coolant Accidents
LUF	Land Use Framework
LWR	Light Water Reactors
MCDA	Multi Criteria Decision Analysis
MMR	Micro Modular Reactor
MOU	Memorandum of Understanding
MOX	Mixed Oxide
MS	Molten Salts
MSR	Molten Salt Reactor
NG	Natural Gas
NPP	Nuclear Power Plant

NRC	Nuclear Regulatory Commission (U.S)
NRCan	Natural Resources Canada
NREL	National Renewable Energy Laboratory
NSCA	Nuclear Safety and Control Act
NWMO	Nuclear Waste Management Organization
OECD	Organization for Economic Co-operation and Development
ONR	Office of Nuclear Regulation (U.K)
OPEX	Operating Experience
OPG	Ontario Power Generation
OPyC	Outer Pyrolytic Carbon
ORNL	Oak Ridge National Laboratory
OTSG	Once Through Steam Generator
PCM	Phase Change Material
PHW	Pressurized Heavy Water
PLNGS	Point Lepreau Nuclear Generating Station
PSRL	Power System Readiness Level
PWR	Pressurized Water Reactor
RMWB	Regional Municipality of Wood Buffalo
SA	Surface Area
SAGD	Steam Assisted Gravity Drainage
SCA	Safety and Control Areas
SCWR	Super Critical Water Reactors
ICEP	Indigenous and Community Engagement Plan
SFR	Sodium Fast Reactor
SiC	Silicon Carbide
SMART	System-integrated Modular Advanced ReacTor
SMR	Small Modular Reactors
TES	Thermal Energy Storage
TRISO	TRi-structural ISOtropic particle fuel
TRL	Technology Readiness Level
VDR	Vendor Design Review

Executive Summary

Markets around the world are signaling a need for smaller, simpler, and cheaper nuclear energy to aggressively pursue low-carbon and clean energy climate change goals. Decarbonization targets have generated significant momentum across Canada and globally with respect to development and deployment of Small Modular Reactors (SMRs). SMRs are expected to play a pivotal role in achieving utility and industrial decarbonization goals.

As outlined in Canada's SMR Action plan[1], innovative technologies such as SMRs are noted to be crucial to growing the economy and improving environmental performance. Developing SMR technology together with governments and key stakeholders will enable the power generation and industrial sectors to advance SMR development and deployment within Alberta and Canada and contribute to positive social, economic, and environmental impacts in Alberta.

SMRs are nuclear power reactors that generate less than 300 MW of electricity per reactor, while traditional utility-scale reactor designs can reach over 1 GW of electricity per reactor. Because of their smaller unit size, SMRs are capable of supporting a broader range of deployment scenarios than their larger traditional counterparts.

This report investigates the possible implementation of nuclear power (SMRs) in the oil sands to reduce greenhouse gas (GHG) emissions and produce steam, and electricity for use at in-situ recovery facilities utilizing Steam Assisted Gravity Drainage (SAGD) for bitumen production. The intent of this report is to investigate and a provide a generic guide for the deployment of SMRs in the Canadian oil sands with a focus on deployment to support SAGD facilities.

Benefits of using SMRs to support the SAGD Industry

- Promising option for clean and **reliable energy**.
- **Low operational and lifecycle carbon** intensity to help meet emission reductions targets.
- May operate for **extended periods without refueling**, reducing the need for frequent fuel deliveries.
- **Scalable** to accommodate a small first deployment and changing energy demands.
- Can support **electrical, process heat and hydrogen** needs.
- Most designs allow **rapid load following**.

[1] Canada's Small Modular Reactor (SMR) Action Plan (smractionplan.ca)

Overview of SMR technology

Nuclear reactor technologies are divided into technology "generations" which, at a high level, describe the technological basis of the reactor design. The existing light and heavy water nuclear power reactor fleet consist primarily of Generation II or Generation III water-moderated and water-cooled designs. SMR technologies under development can broadly be categorized as follows:

- **Generation III+ SMRs** are designs that use either light-water or heavy-water as a coolant and neutron moderator. These designs can be thought of as an evolution of existing utility-class designs that incorporate advances in technology, increase passive safety, and provide a cost advantage compared to Generation III designs.
- **Generation IV SMRs** are designs that typically make use of alternative coolants such as liquid metal, helium, or molten salts. In accordance with the principals laid out by the Generation IV International Forum, these SMR designs aim to improve safety, efficiency, and cost-effectiveness compared to previous reactor designs. Compared to Generation III+ SMRs, Generation IV SMRs have fewer operational reference plants.

SMRs are being designed to exploit economies of multiples by moving as much construction off-site and into factories and module yards as possible. Together with a standardized design that can be deployed multiple times at the same site, SMR builds aim to leverage efficiencies gained in sequential construction to add cost and schedule efficiencies in comparison to traditional large nuclear builds.

Various reactor technologies exist and are under development. Some of the SMR technologies that are currently under development including the following:

	Technology Type	High-Level Description
GEN III+	**Pressurized Water Reactors (PWRs)**	Use pressurized water to transfer heat from the reactor (primary loop) to a secondary loop through a steam generator. This steam is then used to drive a turbine and generate electricity.
	Integral Pressurized Water Reactors (IPWRs)	IPWRs are a class of PWR that integrates the reactor core and steam generator into a single unit. This provides advantages for containment and improves the modularity of the system design.
	Boiling Water Reactors (BWRs)	Feature a single coolant loop in which water is pumped through the reactor core to directly produce steam which is then sent through a turbine generator before being condensed back into water and sent back to the reactor core.
GEN IV	**Liquid Metal Cooled Fast Reactors (LMFRs)**	LMFRs are designed to maintain their neutrons at high energies (1 MeV or greater) and use liquid sodium or lead as a coolant to remove heat from the reactor core. These are typically pool-based reactors which do not require high pressures in the reactor to produce power. The use of liquid metal also provides enhanced thermal performance under accident scenarios as it remains liquid to higher temperatures.
	High Temperature Gas Reactors (HTGRs)	HTGRs use high temperature gas (typically helium) as a coolant to transfer heat to a secondary fluid to produce electricity or high temperature process heat. HTGR's typically use TRISO fuels which together with the use of helium results in improved safety relative to existing reactors.
	Molten Salt Reactors (MSRs)	MSRs are pool-type reactors in which the primary coolant is a fluoride or chloride salt. MSR designs use a variety of fuels including liquid fuels in the fuel salt, liquid fuels in fuel channels, or TRISO fuel. All MSRs share the use of a low pressure, high temperature primary coolant salt, with additional salt loops used to generate steam or process heat.

Siting Assessments for Nuclear Facility

Numerous sources, including the Canadian Nuclear Safety Commission (CNSC) and the International Atomic Energy Agency (IAEA) offer guidance and best practice for evaluating sites for hosting new nuclear-powered facilities. In Canada, sites for hosting SMRs are expected to be evaluated using a graded approach, commensurate with risks posed by the facility's operating parameters and site characteristics (i.e., presence of seismic activity, expected resource development over time, proximity of steam source to end-use applications, availability of cooling water etc.). Because there is flexibility in identifying optimal locations for siting of an SMR, potential licensees are expected to demonstrate the safety case of a site through the CNSC's licensing process and additional environmental assessment reviews. Flexibility in site identification can support the deployment of SMRs at industrial sites by allowing licensees to best utilize an area and to ensure that no undue risk is posed by existing features of the site (i.e., industrial processes). Identifying locations and quantifying their features is necessary to ensure effects on the environment, health and safety, and national security are appropriately assessed, and mitigation strategies developed and implemented where needed.

To support facility siting discussions, nuclear facility siting criteria are discussed along with exclusionary and discretionary siting criteria affecting the social, technical, and regulatory feasibility of a site. This provides a basis for site specific assessments that would be needed during the formal site assessment process for the nuclear integration of SMRs at a SAGD facility. Siting insights are presented with a focus on aspects of the legislative processes that might be novel to clients new to the nuclear industry, where regulatory oversight plays a significant role in ensuring safe operations of these facilities. Information presented is based on publicly available sources and ongoing discussions with Canada's nuclear industry and existing licensees. The IAEA's screening criteria are outlined below and consist of both safety and non-safety related conditions.

Criteria		Category Screening	
Primary	Type	Exclusionary	Discretionary
Volcanism	Lava flow	✓	
	Pyroclastic flow	✓	
	Ground deformation	✓	
	Tephra fall		✓
	Volcanic gases		✓
	Lahars (massive)	✓	
Flooding	River		✓
	Dam break		✓
	Coastal (storm surges, waves, etc.)		✓
	Tsunami		✓
Extreme meteorological events	High straight winds (plow winds)		✓
	Tornadoes		✓
	Tropical storms		✓
	Precipitation		✓
	Sand, dust storms		✓
Human induced events	Aircraft crashes		✓
	Explosions		✓
	Gas releases		✓
	External Fires		✓
	Electromagnetic interference		✓
Nuclear security events			✓
Dispersion	In air and water		✓
Feasibility of implementation of emergency plan		✓	
Implementation of emergency plan			✓
Non-safety	Topography		✓
	Availability of cooling water	✓	✓
	Access to water		✓
	Availability of transport		✓
	Access to national or regional electricity grid		✓
	Non-radiological environmental impacts	✓	✓
	Socioeconomic impacts		✓
	Land use planning		✓

Generic SMR Selection Guide

As an initial screening for the integration of SMR technology with new or existing operating SAGD facilities, a decision tree selection tool was developed. This tool provides a high-level assessment of certain criteria to provide context as to potential process constraints when considering SMR integration.

The decision tree methodology also enables the reader to understand how certain decisions will affect SMR use with thermal in-situ oil sands, while providing context to avenues requiring further exploration and assessment while developing site specific projects.

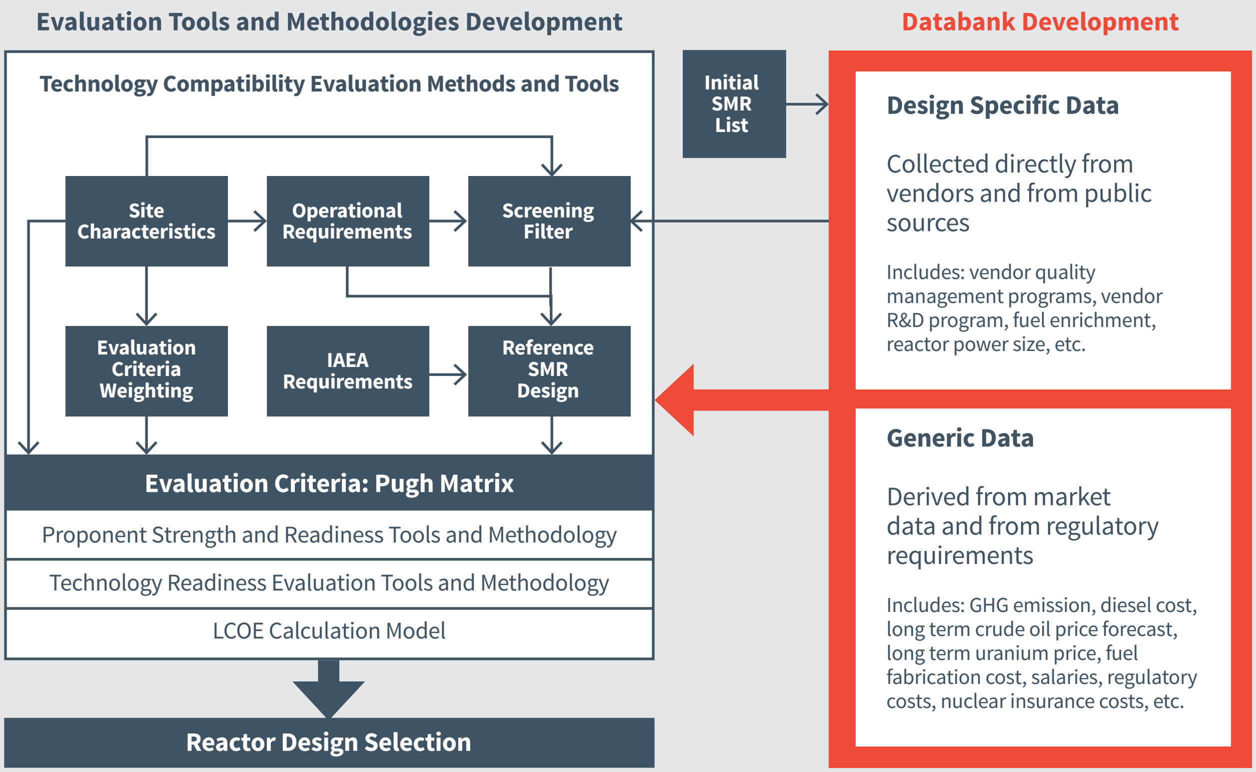
SMR Technology Assessment and Down Selection Methodology

One of the critical steps in SMR technology deployment is the selection of which SMR designs or classes of designs are most well suited tothe application under consideration.

With over 100 SMR designs available in the marketplace at varying levels of development and support, the use of a robust methodology to assess and rank SMR technology and vendor offerings is required to support a more detailed evaluation of a smaller number of technologies in future work.

The technology evaluation methodology presented in this study follows a phased approach. The Figure below provides a graphical summary of the steps involved in the technology assessment and down selection.

SMR Evaluation Methodology



Starting from a broad list of SMR designs and vendor offerings, an initial screening is completed to develop a listing of reactors considered viable for the application under consideration. Based on the intended application to support SAGD processes in Alberta, the following initial screening criteria were used in generating the list of SMR designs for additional study:

- Country of Origin
- SMR Module Size
- Design & Corporate Maturity
- Targeted End Use Application of the SMR Technology
- Site and Process Compatibility

It should be noted that at this stage, the screening criteria are defined as preferences which are used to parse the initial list of SMR designs into a manageable number of SMR designs for future assessment. Where a particular SMR design may not fully meet all the defined technical preferences in each of the categories, exceptions are generally made to ensure that SMR designs that screen well in multiple categories are not removed from further contention due to their screening results in a single category.

Upon development of this list of SMR designs for consideration, a more in-depth assessment of these designs is completed. This assessment is comprised of the following four components:

- **Technology Compatibility Assessment:** This component involves the development of a decision matrix consisting of criteria addressing site specific and process specific items. In this case, the screening matrix consists of items specific to SAGD integration, the ability to meet safety standards as well as other project requirements. Each SMR design is evaluated against each of the criteria. Weighting and normalization values defined by the project team to align with project requirements are then to be used to determine the overall suitability of the technology relative to the technical and project deployment environment.

- **Technology Readiness Assessment:** The Technology Readiness Assessment evaluates the technology readiness of both the components of given SMR technology as well as readiness in specific implementation of the design.

- **Proponent Strength and Readiness Assessment:** This assessment evaluates the proponent group defined as consisting of three different entities who together are significantly responsible for the success of a project including the Licensee/Operator, the Technology Vendor, and EPC/EPCM partners in deployment.

- **Levelized Cost of Energy (LCOE):** A variety of estimates are used to develop representative LCOE's that can be used to compare the selected SMR designs against one another. At this stage of the assessment, publicly available data from 3rd parties, in-house databases, and publicly available vendor estimates are used along with cost estimates developed to quantify any large-scale differences in the implementation of the different technologies specific to SAGD production.

On completion of the assessment of each of the four components above, a final ranking assessment can be completed to determine a single or set of down-selected technologies. It is noted that technology selection is a complex endeavour, strongly characterized by conflicting aims that are likely to involve trade-offs. While it is natural to look to combine the results of the four assessment components into a single 'value', this is strongly cautioned against. The Technology Compatibility, Technology Readiness, Proponent Readiness, and LCOE assessments arguably measure very different aspects of an SMRs fit for a given project. By assembling the results of these assessments in a single value, an unrealistic portrayal of the assessment itself may emerge. Instead, evaluating the results of the components individually and together as a whole in a structured, explicit and transparent manner by all members of the project team are suggested to ensure that an appropriate selection is made.

SMR Site Integration with SAGD Facilities

SMR technologies are generally designed first and foremost for electricity production. While integration with industrial processes has been proposed by many SMR vendors (and is in development by some vendors), the authors of this report are not aware of a precedent for the integration of an SMR with a SAGD steam production facility. Given the uniqueness of this applications, several interfacing facility designs may exist for a selected SMR technology. To evaluate how the interface between the SAGD facility and the SMR's Nuclear Island may be designed, different deployment scenarios have been developed and evaluated for feasibility. This specifically includes important considerations such as radiological protection, process upset conditions, and reliability of process steam production.

In evaluating the integration of water-cooled reactor designs with a SAGD process, challenges arise due to the SMR designs having a lower steam saturation temperature than the SAGD process water. Without the availability of other higher temperature process streams to boost the temperature of the steam from the SMR, other configurations to reach the necessary steam conditions were investigated. This includes the use of supplemental heating (generally in a separate medium such as molten salt) or the use of steam compression. While both approaches are viable and allow the use of water-based SMRs in this application, the additional complexity of the interfacing facility in this case needs to be weighed against the value that water-based SMRs can bring to this deployment environment.

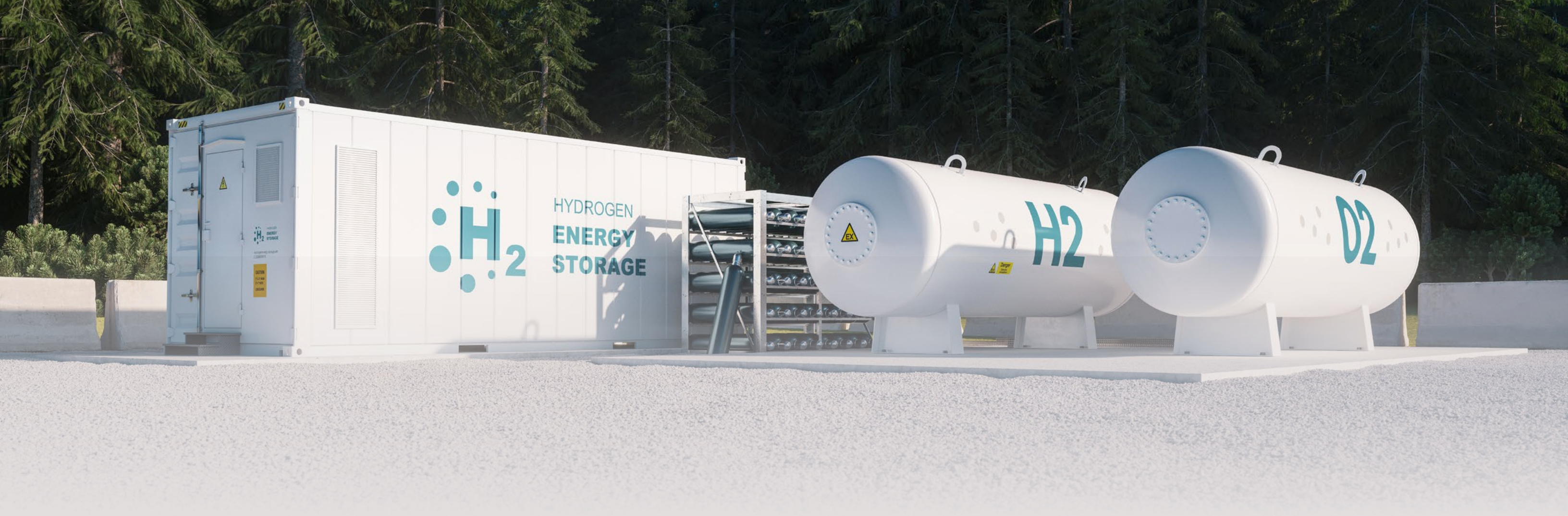
Many of the other SMR technologies (e.g., LMFR, HTGR, MSR) have process steam temperatures and pressures sufficient to allow the reactors to be directly coupled to the SAGD process. However, the use of an intermediate fluid to support radiological separation requirements, to isolate the reactor from process upsets, and to allow for the use of a 'standard' utility design is still considered.

Reference SAGD Facility

For this report, a reference SAGD central processing facility (CPF) based on the Canada's Oil Sands Innovation Alliance (COSIA) SAGD Template (ML-WLS–OTSG) has been adopted. As described in the COSIA SAGD reference plant report, this CPF reference case contains:

- An Electric Submersible Pump (ESP) as the Mechanical Lift (ML) technology.
- Warm Lime Softening (WLS) for water treatment.
- Once Through Steam Generators (OTSGs) to meet steam production requirements.
- Power imported from the grid.

Operational characteristics of this 33,000 barrel (bitumen) per day facility have been assumed to require approximately 15,757 m3/d Cold Water Equivalent (CWE) of steam (100 wt.%, 10 MPag, and 312°C) for a Steam-to-Oil (SOR) ratio of 3.00 (wet). This basis is consistent with a thermal duty of approximately 362 MWth. For this same basis, it is assumed that a maximum of 18 MWe is required to meet site load demand.



While the COSIA reference case assumed that this power would be provided by the grid, in many cases it is desirable to generate electricity from an SMR on site rather than purchase from the grid. In deployment scenarios with electricity production, it is suggested that all generated nuclear energy should supply heat to a common loop. This would increase the overall reliability of SAGD steam production through the ability to divert heat from power to SAGD steam production. Such a deployment comes at the cost of increased variability in power output. Additionally, for a co-generation scenario, two production streams (SAGD steam and electricity) are needed which increases the complexity and number of potential options of the interfacing facility design. As a result, various co-generation deployment configurations have been explored.

Based on the typical conditions at a SAGD facility, adiabatic dry cooling has been assumed as the most appropriate power-cycle heat rejection mechanism in all configurations investigated in this study.

Hydrogen Production

Low temperature and high temperature hydrogen production processes were evaluated for compatibility with an SMR. The hydrogen production technologies were evaluated using performance characteristics and CAPEX/OPEX estimates. Based on the results of the assessment, one low-temperature electrolysis technology and one high-temperature electrolysis technology was selected to calculate a Levelized Cost of Hydrogen (LCOH).

Based on the selection criteria included in this evaluation, the highest rated low-temperature electrolysis technology was alkaline water electrolysis (AWE), and the highest rated high-temperature electrolysis technology was solid oxide electrolytic cell (SOEC). The LCOH calculated (based on a levelized cost of electricity (LCOE) of $61 /MWhe CAD) for the two hydrogen production processes were $6.21/kg CAD for AWE and $6.13/kg CAD for SOEC. A sensitivity analysis showed the impact of utilization, electricity cost and discount rate on the LCOH. The greatest impact observed was from utilization of the electrolyser plant. The LCOE had the second greatest impact on LCOH. An increase in LCOE contributes to a higher OPEX which drives the LCOH up.

Coupling electrolysers to an SMR presents unique challenges and opportunities. Challenges are mainly associated with the LCOE which is expected to be higher for a nuclear system compared to renewables such as solar and wind. This is because the infrastructure and site development are more intensive for nuclear to electricity systems. Furthermore, the time scale is much longer for new nuclear facilities compared to renewables. On the other hand, an SMR system can deliver a reliable and constant electrical supply for electrolysis, which ensures a high uptime for the hydrogen plant and minimizes or eliminates the need for electricity storage.

In the analysis, it was noted that AWE has a high TRL and a large commercial deployment footprint which provides higher confidence in the LCOH compared to SOEC. Completing detailed site designs would improve the confidence for both technologies. Based on the calculated LCOH, the use of SOEC with an SMR is a competitive option. In addition, the constant electrical supply and steam availability align with SOEC input requirements. The analysis concluded that at the present time the recommendation is to utilize AWE electrolysers.

Review under Canada's Impact Assessment Act and Three Sequential Licences Issued Under the Nuclear Safety and Control Act are Required to Begin Commercial Operation of SMR > 200MWth

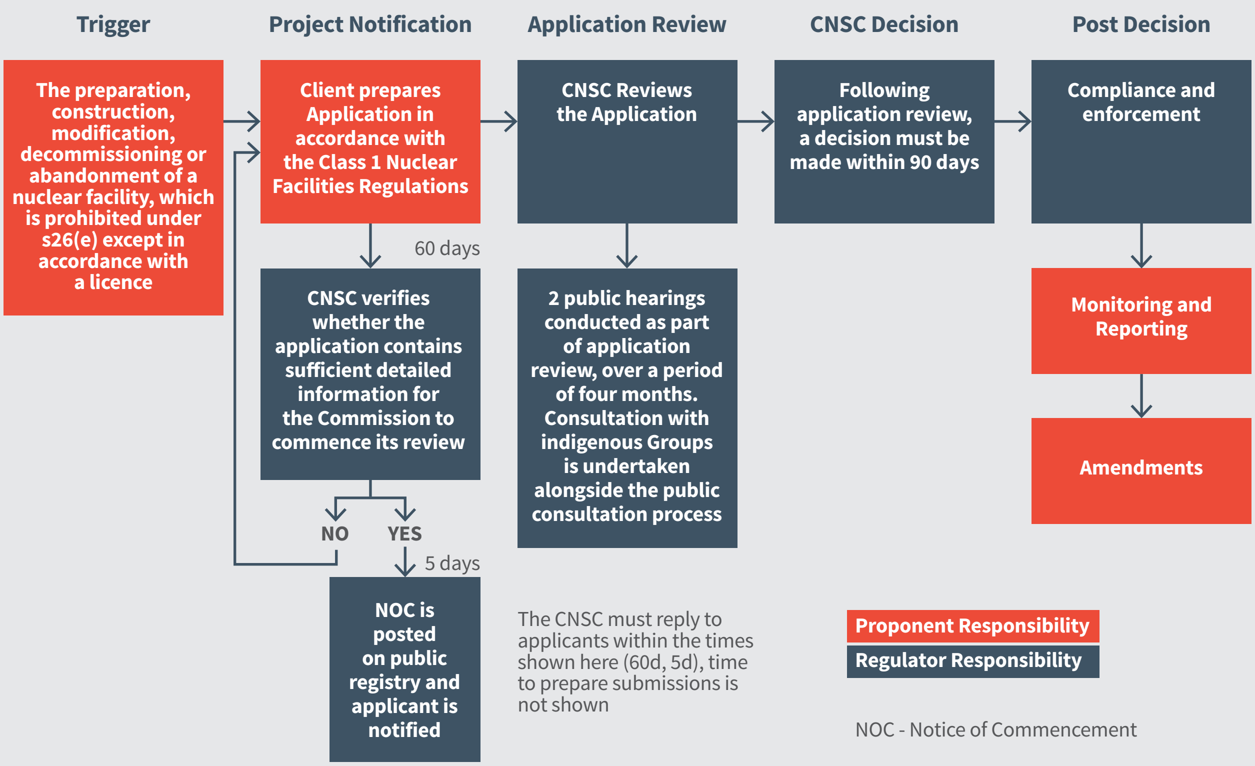
Licensing and Regulatory Approvals

The use of nuclear energy is subject to a rigorous regulatory regime that plays a significant and deterministic role in its deployment, from conceptual study through to construction, operations and eventual decommissioning and closure. This complex, inter-governmental context is important to understand, notably due to the novel and untested regulatory environment posed by the deployment of a First-of-a-Kind (FOAK) SMR in Alberta. This report provides an understanding of how regulatory factors might influence the feasibility for nuclear power generation within Alberta's oil and gas sector.

In Canada, nuclear energy is solely regulated by the federal government through the CNSC , however non-nuclear considerations are regulated by a variety of other federal, provincial/territorial, and municipal governments and agencies. During the planning and project development phases of a new nuclear facility, environmental and social considerations commonly studied in Environmental Impact Assessments (EIA) are regulated by a mixture of federal and/or provincial (or territorial) government bodies.

Three sequential licences (Figure above) granted by the CNSC, at least one EIA (or impact assessment) review, and a provincial approval will be required to begin commercial operation of an SMR in Alberta. These licences and the federal impact assessment are likely to be critical path to commercially operating a new nuclear power plant in the province and could take 10-12 years to complete. The initial licence request (Licence to Prepare Site) and impact assessment report are jointly submitted as one application to reflect the federal government's principle of "one project, one assessment".

CNSC procedures as per Nuclear Safety and Control Act

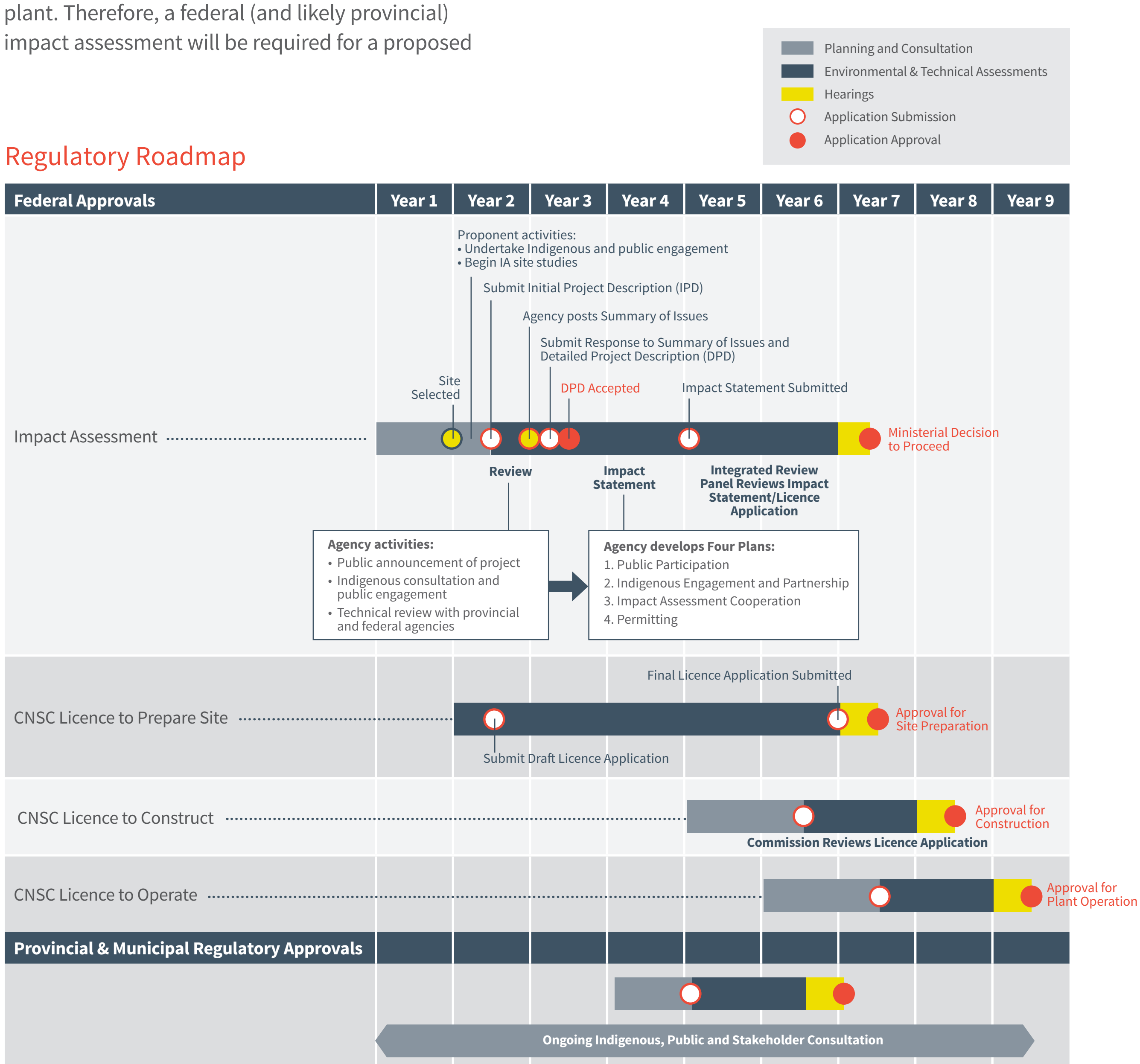


As deployment of a nuclear-powered facility has never been undertaken in the province, there are FOAK considerations that present uncertainty in the overall regulatory process, most likely resulting in increased timelines for approvals needed for navigating the regulatory landscape. Nonetheless, the Government of Canada has repeatedly signaled its readiness for the emerging use of SMRs across the country and is committed to ensuring the safe use of nuclear energy for the next generation of reactors.

For the SMRs under consideration in this present study, all are expected to exceed 200 MWth and will not be co-located with an existing licensed nuclear power plant. Therefore, a federal (and likely provincial) impact assessment will be required for a proposed SMR facility to ensure that no significant adverse environmental, health, social, and economic impacts will occur over its full lifecycle. This impact assessment is a lengthy and semi-novel regulatory requirement, having replaced the former federal environmental assessment process previously required only by the Nuclear Safety and Control Act (NSCA) and governed solely by the CNSC (Figure at bottom of previous page).

Key regulatory opportunities influencing the preparation, construction and operation of an SMR facility in Alberta are reflected in the roadmap in the Figure below.

Regulatory Roadmap



Indigenous and Community Engagement

Engaging with Indigenous and non-Indigenous community members is an essential part of any project's master planning process – particularly when discussing nuclear energy, which is tantamount to introducing a new industry in the province. It is important to note that nuclear power will require extensive public engagement and education as well as the development of a tailored provincial regulatory - and therefore Indigenous consultation and public engagement-framework. It will also be an industry that is regulated federally, requiring involvement of the CNSC and IAA. These additional elements can pose challenges to the project but can be mitigated by early and effective engagement. The government alongside the project proponent will play an active role in the public and Indigenous engagement process as defined herein. An Indigenous and Community Engagement Approach has been outlined in the report.

Project Execution Planning

Any SMR deployed in a SAGD environment would be a large project involving a CAPEX likely in excess of $1 billion CAD. Due to the large capital outlay associated with the project, a review of different contracting models was completed considering contracting models and how they may be applied for SMR new build technologies. In this study, three different execution models have been considered for the construction of the SMR Facility: The Engineering/ Procurement/Construction contractor (EPC) model; the Engineering/Procurement/Construction Management (EPCM) model; and the Integrated Project Delivery (IPD) model.

While each contracting approach presents advantages and disadvantages, first-of-a-kind projects present unique challenges and uncertainties. Given the parallel timelines required for regulatory submittals and the progression of site-specific designs, obtaining a fixed project scope with sufficient detail for a high-quality bid from an EPC contractor to support the project schedule may be difficult. Due to this emerging technology, the owner and EPC contractor must take a collaborative approach given the first-of-a-kind risk profile. Furthermore, the risk associated with first-of-a-kind projects, and specifically with a new nuclear project in a new to nuclear jurisdiction may demand very large risk premiums from the EPC contractor or may narrow the market sufficiently that obtaining competitive
bids is not practical. While different commercial models within an EPC execution framework may help to alleviate some of these risks, many will remain as features of the EPC project execution model.

The EPCM model provides a greater level of flexibility than the EPC model and allows for a more sequential definition and release of data as work packages are finalized rather than all at once in order to obtain an EPC bid. This model also provides additional level of control to the owner on the engagement of specialty subcontractors and the integration of the technology vendors with the execution team. Moving further towards a collaborative environment, the IPD model looks to create a project environment where shared risk management and transparency are essential for success. While this type of collaborative environment can foster new technology developments, ensuring that the right partners for technology development, engineering, and construction are selected and ultimately are aligned in terms of incentives for project success is critical.

Ultimately, the selection of a particular project execution model depends on the owners' priorities, experience, risk appetite, and the specific needs of the project.

Based on the same considerations, a Project Execution Plan needs to be developed. A project execution plan encompasses a project's objectives, scope, stakeholders, timeline, resource allocation, risk management, and communication strategies. Additionally, it highlights the importance of execution strategy models in guiding the project's progress and ensuring its ultimate success.

Implementation Schedule

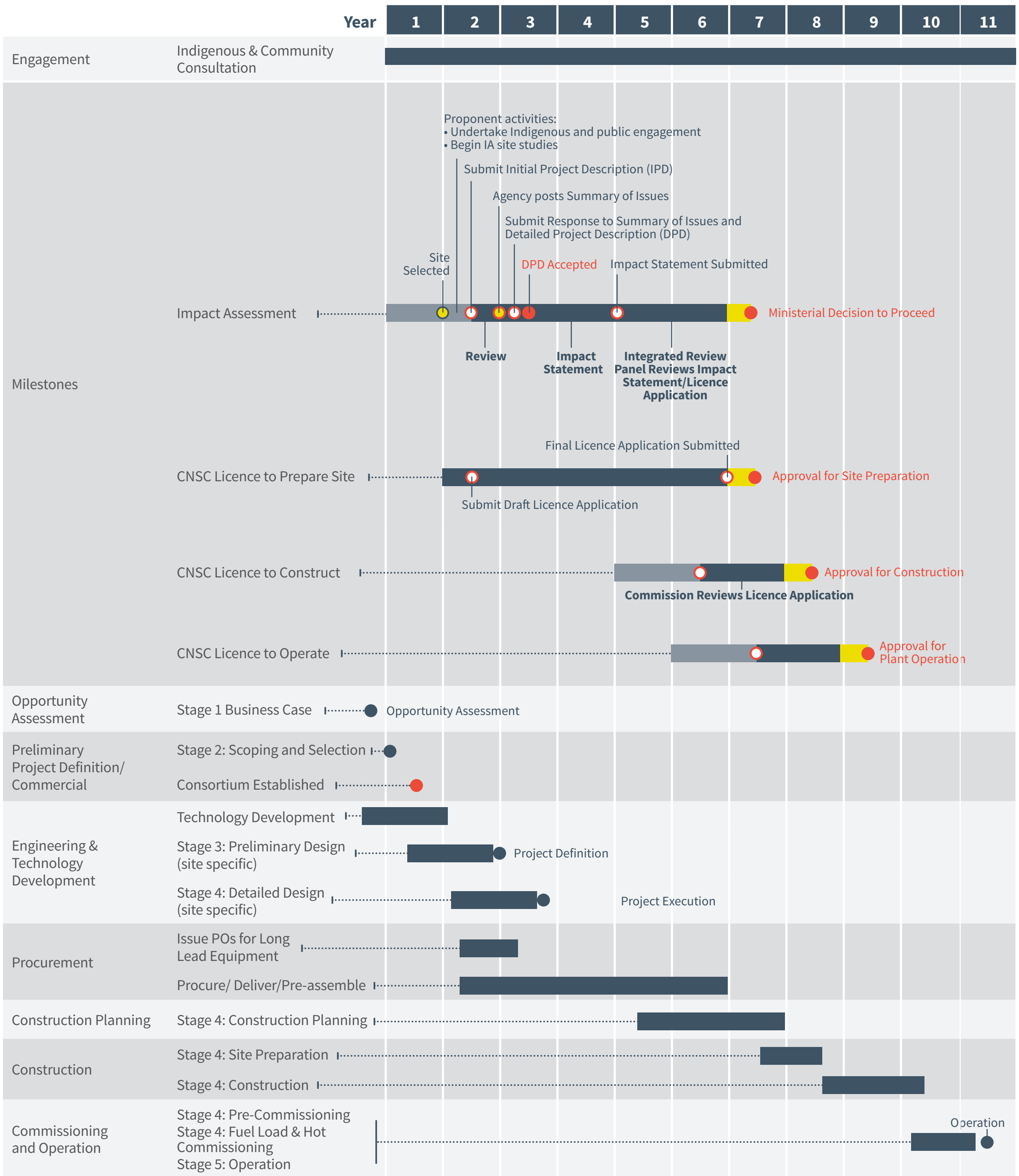
The deployment of a new nuclear technology, in a new to nuclear jurisdiction, is a significant undertaking. As a Class 1A Power Reactor facility, any SMR deployed to support SAGD operations would require licensing by the Canadian Nuclear Safety Commission under Canada's nuclear regulatory framework. Furthermore, based on the assumed size of the SMR facility (in terms of thermal output), the project would require a federal Impact Assessment. In parallel and in support of these activities, project specific developments in terms of site assessments, adapting the SMR design for the selected site, and the design of the interfacing facility are required.

A summary of a representative project schedule is presented in the Figure on the following page. The schedule provides an overview of the complete SMR project life cycle up to commissioning and operation as well as high-level milestones that should be targeted in the development of the project execution plan. While anticipated approvals and licensing timelines have been included in the schedule, it is noted that these are subject to change based on engagements with the regulators, Indigenous communities and other stakeholder groups. Furthermore, depending on whether the SMR technology selected for deployment is a first-of-a-kind deployment or if it has been demonstrated previously elsewhere, the level of engineering and technology development may significantly change. In addition, no time has been assigned for the development of a nuclear operations organization.

The baseline assumption for early deployment of an SMR for SAGD applications is that an existing nuclear operator would support the operation of the facility. Should this not the case for a specific project, additional activities would be required to affect an organizational transition from an operating organization to a nuclear operating organization.

As any potential project progresses, these timelines should be verified with all affected and interested parties. In viewing the execution schedule, design has been frontloaded relative to the licensing process. As the licensing process including the Impact Assessment is assumed to be the critical path of the project, delaying some design activities while planning progresses may be acceptable to provide more flexibility in project outlays. Note the schedule depicts an overview of the project life cycle with durations that may change depending on different aspects related to the siting process along with the type of fuel to be used and the procurement logistics and regulations required to be met. The schedule is also dependent on workforce availability and proficient resources within the government, regulator, contractor etc. *Please note that these timelines are best estimates as of date of this report and there is still significant uncertainties in many areas.*

Level 1 Implementation Schedule



Lifecycle Planning: Fuel

Depending on the SMR technology adopted for deployment in a SAGD environment, the fuel supply chain may either leverage significant existing infrastructure (e.g., water-based reactors) or may require the development of a new fuel supply chain. One notable aspect of many Generation IV reactors is that they have been designed to use High-Assay Low Enriched Uranium (HALEU) as a fuel. This is different than the majority of the existing operating fleet of power reactors which either use Low Enriched Uranium (LEU) or natural uranium (as in the CANDU reactors).

LEU and HALEU are defined based on the amount of fissile U-235 present in the fuel. Low enriched uranium fuel is present in most of the operating light-water reactor fleet in the U.S. and around the world. While the enrichment level may vary between fuel types and between plants, it is generally less than 5% U-235 by weight. Multiple commercial sources of LEU exist currently in the market.

HALEU fuel on the other hand is enriched to between 5% and less than 20% U-235 by weight. Unlike LEU, HALEU is not widely available and has historically been produced in Russia. Given current issues with Russian supply chains, the development of an alternate source of HALEU is required. The US Department of Energy (DoE) has recognized this gap and is assisting in developing the HALEU supply chain in the United States to meet the anticipated demand from SMRs.

Lifecycle Planning: Waste

In radioactive waste management, materials are presumed to be hazardous until proven to be safe beyond a reasonable doubt. If data is not available to prove that waste should be handled, treated, and disposed of through methods aligned with a lower level of waste classification, higher waste classification methods are used by default.

In Canada, the long-term liability for high-level (fuel) waste disposal and management is held by the Nuclear Waste Management Organization (NWMO). The NWMO was established in 2002 by Canada's nuclear electricity producers in accordance with the Nuclear Fuel Waste Act. The NWMO is responsible for designing and implementing Canada's plan for the long-term management of used nuclear fuel. To fund the NWMO, a small fee is collected and deposited into a spent fuel management fund when nuclear energy is sold. Annual deposits from these spent fuel management funds are then made to the NWMO to fund disposal of the spent fuel. Paying for the long-term management of used nuclear fuel is a relatively small portion of the cost of electricity at approximately 0.1 cent per kilowatt hourof electricity produced.

As no SMRs currently under development are proposing to use the CANDU fuel design, there is currently no finalized plan between prospective SMR licensees and the NWMO for the long-term management of spent fuel or high-level waste generated by SMRs. It is expected that this will be resolved as the market for SMRs matures

For low and intermediate-level waste, the liability and financial obligation for management and disposal currently lies with the nuclear licensees (operators). However, the NWMO has recently submitted recommendations for an Integrated Strategy for Radioactive Waste that would transfer all intermediate- and high-level waste ownership to the NWMO for their management. Low-level waste would continue to be managed by waste generators and waste owners to either develop their own near-surface disposal facility or engaged other third parties such as EnergySolutions in the United States to accept and handle their low-level waste.

In summary, there will be a solution and final destination for all types of nuclear waste generated by an SMR facility; however, some of the details are still under development given some of the new waste streams anticipated to be generated by SMR deployment. While the cost for waste management and disposal is typically included in levelized-cost-of-energy calculations, exact values are as of yet unknown, and assumptions based on the current practice of operating nuclear power plants are typically adopted.

Lifecycle Planning: Decommissioning

Decommissioning is a normal part of a nuclear facility's lifetime. As part of a new nuclear facility's licence approval, a decommissioning plan is required that demonstrates the feasibility of decommissioning the plant at end of life and provides assurance that provisions are in place initially and over the project lifecycle to cover associated decommissioning costs.

In Canada, the decommissioning of a nuclear power plant is an activity that requires a CNSC licence (Licence to Decommission). Regulatory document REGDOC-2.11, Framework for Radioactive Waste Management and Decommissioning in Canada, provides overview information on the governance and regulatory framework for radioactive waste management and decommissioning in Canada. REGDOC-2.11.2, Decommissioning, sets out requirements and guidance regarding the planning and preparation for as well as the execution and completion of decommissioning.

Project Financials

The major input to the economic impact of building an SMR in Alberta is the Capital Expenditure (CAPEX) to build the facility. The CAPEX is made up of the Nuclear Island equipment costs, the non-nuclear integration costs with the SAGD plant, and any additional infrastructure costs required to build the facility, provide access, security, and maintenance infrastructure. In addition to these direct costs, there are the costs for engineering, regulation, procurement, construction, commissioning, start-up, and operation.

The costs presented herein are intended to be representative of a generic SAGD integration with an SMR based on COSIA representative facility for sizing. Actual implementation costs will vary based on:

- The SMR technology selected to be deployed.
- The location of the facility.
- The size of the facility.
- Whether the technology implemented widely or is FOAK/near FOAK deployment.
- Configuration of interfacing facility including requirements (if any) for thermal heat storage.
- Relationship between SAGD site owner and any other parties involved in the SMR operation.

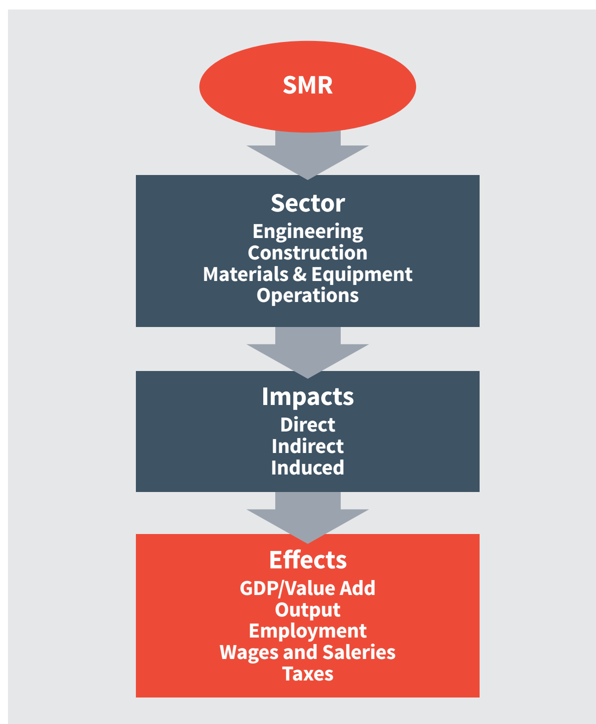
The size of the SMR facility used for this assessment was 400 MWth. The costs adopted for this study are as follow:

- CAPEX : $1.5 Billion to $4.5 Billion (for the economic impact assessment $3.0 Billion for a 400MWth SMR facility was used)
- OPEX: $32.5 Million to $97.5 Million per annum

Note that CAPEX and OPEX values are provided as technology-agnostic, representative values and may not be reflective of the actual costs of SMR deployment at SAGD facility. The OPEX cost are specific to the nuclear island and interfacing facility.

Economic Impact Assessment

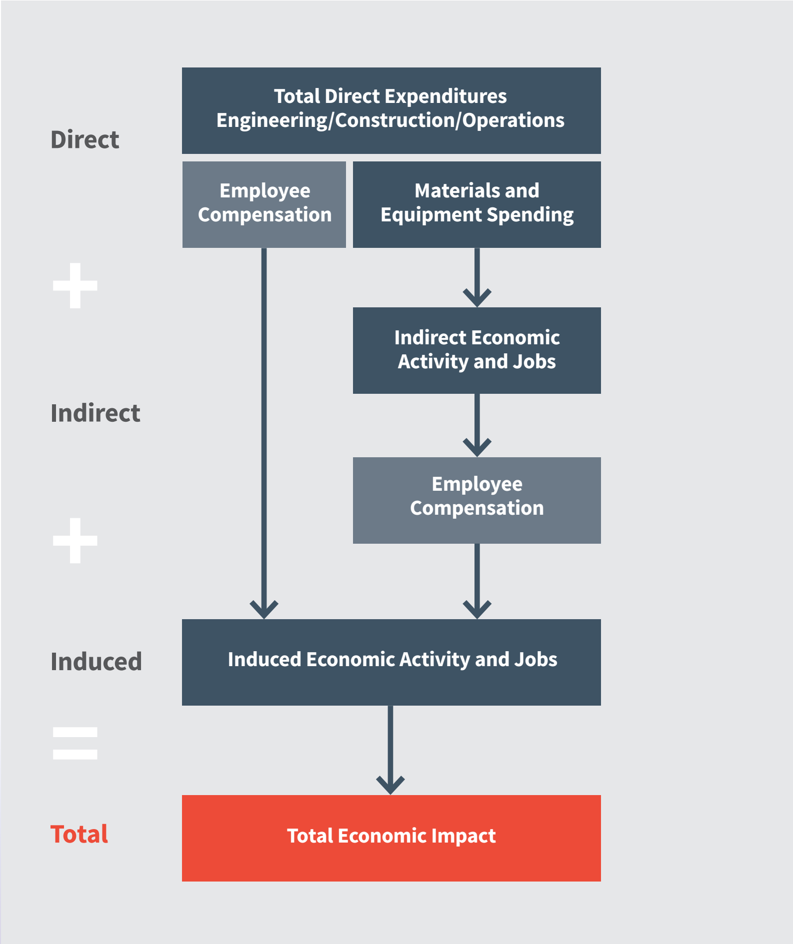
Direct expenditures related to an SMR project supporting SAGD operations, whether resulting from the one-time engineering and construction of the SMR or annual operations, will support significant economic benefits for the economies of Alberta and Canada. To quantify these benefits, an economic impact assessment has been completed following the framework outlined in the figure below.



Framework for assessing the impact of SMR

Economic impacts of an SMR deployment at a SAGD facility would occur at the following levels (figure to the right):

- **Direct Impacts** – The economic activity and employment associated with the SMRs themselves. During the construction period this includes the on-site construction labour, as well as the impacts associated with design and engineering of the plant, construction management, and commissioning of the plant. During the annual operations this includes the impacts associated with operations and maintenance of the plant.
- **Indirect Impacts** – The economic activity and employment supported via the supply chain purchase of materials and equipment from Alberta and Canadian-based suppliers. During the construction period, this includes the spending on the materials and equipment needed to construct the plant, such as steel, concrete, pumps, tanks, turbines, and electrical transformers. During the annual operations of the plant, this includes the spending on fuel, replacement parts and equipment as well as other supplies needed to operate the plant.
- **Induced Impacts** – The economic activity and employment supported by those directly or indirectly employed in the construction and operations of the plant spending their incomes on goods and services in the wider Alberta and Canadian economies. This spending helps to support jobs in the industries that supply these purchases and includes jobs in real estate, retail, and companies producing a variety of consumer goods and services.



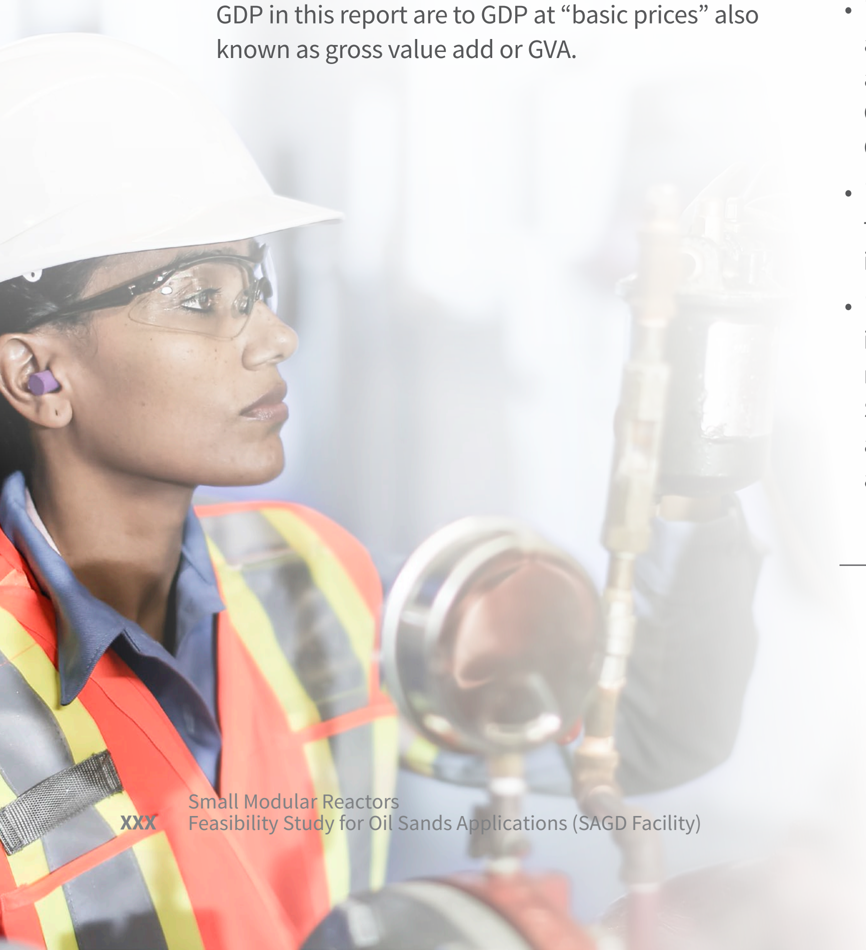
Levels of Economic Impact

A customized economic impact model was developed to estimate economic impacts of SMRs using detailed input-output data from Statistics Canada for both the Alberta and national economies.[4] The main inputs to the economic impact model are the CAPEX and OPEX estimates discussed above. To understand the distribution of spending across industries and sectors the model incorporated data from the World Nuclear Association[5] and research from the Canadian Nuclear Laboratories.[6]

While the above methodology estimates the economic impacts of the SMR build itself on the economies of Alberta and Canada, it does not account for the potential additional benefits generated due to the demonstration of the feasibility of SMR technology in decarbonizing industrial applications. Successful integration of an SMR with a SAGD facility could catalyze significant additional investment in SMRs as a low-cost, carbon-free, reliable energy solution for decarbonization of the oil & gas and other industrial sectors with economic impacts accruing to Alberta and Canada as a result of subsequent projects and deployments.

We used the model to estimate the following economic impacts:

- Gross Domestic Product (GDP) – all references to GDP in this report are to GDP at "basic prices" also known as gross value add or GVA.
- Employment
- Wages and salaries
- Select taxes



All told the proposed project will support the following economic impacts:

Construction Period

- 51% of the construction spending (labour, materials, and equipment) will occur within Alberta and 82% will occur within Canada.
- The approximate $3 billion in total capital spending will support nearly $3.5 billion in GDP locally in Alberta and over $4.8 billion in Canada.
- 17,870 total job-years in Alberta, an average of 4,4709 total jobs per year over the assumed 4-year construction period and 23,920 total job-years across Canada, an average of over 5,980 total jobs per year.
- $1.5 billion in total wages and salaries in Alberta and $1.9 billion across Canada. The construction period will also support $368 million in fiscal impacts across Canada

Annual Operations

- 62% of the operations and maintenance spending (labour, materials, and equipment) will occur within Alberta and 84% will occur within Canada.
- The operations of the facility will generate an average of $71.9 million in total spending per annum, which will support $131.2 million in total GDP locally in Alberta and $154.6 million across Canada annually.
- The facility will directly employ 246 employees. All told the annual operations will support 501 total jobs in Alberta and 546 total jobs across Canada.
- The annual operations will support $37.9 million in direct wages and salaries and will support $48.1 million in total wages and salaries in Alberta and $56.2 million across Canada. The operations will additionally support $22.7 million in fiscal impacts across Canada per annum.

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[2] Please see the Appendix J for additional details on the models.

[3] Nuclear Power Economics | Nuclear Energy Costs - World Nuclear Association (world-nuclear.org)

[4] Canadian Nuclear Laboratories. 2020. "Assessment of Small Modular Reactors." Report No 153-120200-REPT-40

Key Takeaways

SMRs are a feasible option for the provision of electricity and steam in the oil sands to support net-zero energy production at in-situ recovery facilities.

While no specific recommendations are made in this report, major considerations associated with SMR deployment planning are presented along with commentary to assess the potential impacts of decisions and their influence on other decisions.

Given the need for both process steam and electricity in the reference SAGD facility, it is suggested that all generated nuclear energy should supply heat to a common header/storage loop. By passing the heat through a common loop, the reliability of SAGD steam production can be improved through SMR outages based on the ability to preferentially generate steam instead of providing power to the grid.

In Canada, sites for hosting SMRs are expected to be evaluated using a graded approach, commensurate with risks posed by the facility's operating parameters. Potential licensees are expected to have flexibility in identifying locations for an SMR at existing SADG operation and are expected to demonstrate this through the site licensing process and impact assessment review. Flexibility in site identification can support the deployment of SMRs at industrial sites by allowing licensees to best utilize site areas and to ensure that no undue risk is posed by existing features of the site (i.e., industrial processes).

Complex, inter-governmental regulatory context is important to understand, notably due to the novel and untested regulatory environment posed by the deployment of a First-of-a-Kind (FOAK) SMR in Alberta. This context provides an understanding of how regulatory factors might influence the feasibility for nuclear-powered generation within Alberta's oil and gas sector. The FOAK considerations that present uncertainty in the overall regulatory process, will most likely result in increased timelines for approvals needed for navigating the regulatory landscape. Nonetheless, the Government of Canada has repeatedly signaled its readiness for the emerging use of SMRs across the country and is committed to ensuring the safe use of nuclear energy for the next generation of reactors. Engaging with Indigenous and non-Indigenous community members is an essential part of any project's master planning process – particularly when discussing new technology associated with nuclear energy.

In the planning of any nuclear power project at a SAGD facility, the following critical items should be considered:

- The integration of an SMR with a SAGD operation represents a novel application of nuclear technology. Ensuring nuclear and industrial safety is paramount.
- As with any major project, early engagement with Indigenous communities, regulators such as the CNSC, IAA, and public and industry stakeholders is critical. Given the introduction of a novel nuclear technology into a new jurisdiction, building relationships with Indigenous and local communities and stakeholders is required to help build an informed and receptive community.
- Due to the regulations around the management of nuclear power plants, existing nuclear power plant operators should be leveraged to operate the first SMRsplants for supporting SAGD facilities. Over time, additional operations models may be investigated; however, partnering with existing nuclear operations organizations provide a significant benefit to project viability in the near term.
- For any potential SMR deployment, a detailed site assessment following the principles and guidance provided by both the CNSC and the IAEA should be completed to ensure that the sites do not possess any fatal flaws, significant issues impacting overall cost or schedule, or external hazards introduced due to the co-location next to an active industrial facility. As SAGD operations represent a novel application of nuclear technology, ensuring a robust assessment of both site and integration conditions will be important for licensing and technical development.
- Different SMR technologies exist to address the steam and power demands of SAGD facilities. To ensure that an optimal technology partner has been selected, a robust down selection of SMR technologies should be conducted reflective of the SAGD site operational and business needs.

1. Introduction

Markets around the globe are signaling a need for smaller, simpler, and cheaper nuclear energy in a world that will need to aggressively pursue low-carbon and clean energy technologies to meet climate change goals. Decarbonization targets have further generated significant momentum across Canada and globally with respect to development and deployment of Small Modular Reactors (SMRs) and very Small Modular Reactors (vSMR) (also known as microreactors). As the net-zero transition accelerates, SMRs and vSMRs are expected to play a growing and pivotal role in achieving net-zero energy production for both electricity and process uses.

SMRs are advanced nuclear power reactors with typical reactor unit sizes of less than 300 MWe compared to traditional utility-scale reactor designs which can reach over 1 GWe per reactor. With a smaller unit size, and through leveraging economies of multiples, SMRs can support a wider range of deployment locations and environments than traditional nuclear power plants.

This report investigates the feasibility of implementing SMRs in the oil sands to support net-zero greenhouse gas (GHG) emission steam and electricity goals at in situ facilities that utilize Steam Assisted Gravity Drainage (SAGD) for bitumen production. The intent of this report is to investigate and provide a generic guide for the most feasible approach to deploy SMRs in the oil sands (SAGD) as of the date of the report. It is noted that the SMR field is rapidly advancing and, as such, this report represents a snapshot in time. Independent assessments of the market for specific sites, applications, or in the future should be done to ensure the conclusions of this report remain valid.

2. Scope and Approach

This report presents a generic guide for site evaluation and SMR technology selection in the context of SAGD applications. In assessing the feasibility of the deployment of SMRs in the oils sands for SAGD extraction, the Canada's Oil Sands Innovation Alliance (COSIA) SAGD Template[8] was adopted as the reference site and process basis for this study.

Given the rapidly changing SMR landscape, both in Canada and internationally, a holistic methodology is presented for assessing the feasibility of SMR technologies available in the market for SAGD applications. The assessment methodology considers aspects such as technology compatibility with the project/application, technology readiness, proponent readiness (inclusive of technology vendors, nuclear operators, and other parties involved), as well as cost competitiveness using a Levelized Cost of Electricity metric. The assessment presented in this report considers the COSIA SAGD reference facility. As such, while the methodology for the assessment of SMR technologies remains valid, specific assessment metrics may vary from site to site and application to application. As such, ensuring that an appropriate basis is adopted prior to the application of this assessment methodology is critical to its overall success. Furthermore, while the selection methodology can be applied to a wide variety of applications, the specific priorities of the end-user of the technology will inform the ultimate results from the study, whether it be technological compatibility with the site under consideration, deployment timelines, cost, or other metrics.

To support facility siting discussions, nuclear facility siting criteria are discussed along with exclusionary and discretionary siting criteria affecting the social, technical, and regulatory feasibility of the site. This provides a basis for site specific assessments that would be needed during the formal site assessment process for integration of SMRs at a SAGD Facility. Regulatory insights are presented with a focus on aspects of the legislative processes that might be novel to ‘new to nuclear’ clients. Information presented is based on publicly available sources and ongoing discussions with Canada's nuclear industry and existing licensees. An Indigenous and Community Engagement Approach was developed based on desktop research and analysis, practical experience in completing similar engagements, and discussion with stakeholder groups engaged in this study. This approach will support engagement efforts with Indigenous local communities, and other stakeholders in regions of interest.

This report aids in understanding the full lifecycle of a potential SMR project for SAGD applications including external impacts and supply chain and logistics plans. It includes schedules and timelines with key milestones and critical path items. Investigation of various types of procurement delivery strategies is conducted to provide a qualitative analysis of the advantages and disadvantages of each model. A qualitative preliminary strategy for Project Execution is presented. Full lifecycle planning with Fuel cycle analysis, waste management plan, and decommissioning requirements is described.

Based on the project configuration designed and the preliminary project execution plan developed, capital and operating Class V cost estimates (+100%/-50%) were prepared. These estimates are based on publicly available information, with additional associated project costs and a full project lifecycle economic analysis.

Economic impacts that will be supported by the proposed reactor are assessed, including gross value add, employment, wages, and salaries, as well as the resulting tax revenue impacts. It further presents the economic impact-based project financials and associated project schedule by using an economic input-output (I-O) model with Alberta economy coefficients.

This report also evaluated hydrogen as a potential alternative for SMR heat utilization. Low temperature and high temperature hydrogen production processes were evaluated for compatibility with an SMR.

3. Generic Site Description

Alberta thermal in situ oil sands Steam Assisted Gravity Drainage (SAGD) operational schemes employ high pressure steam to recover sub-surface bitumen. Typically, a Central Processing Facility (CPF) produces the steam using natural gas fired boilers and cogeneration through waste Heat Recovery Steam Generators (HRSGs) if on-site natural gas turbine power generation is deployed. The Boiler Feed Water (BFW) that is supplied to steam generation is treated water recovered from the steam condensate that is produced with the bitumen in the form of an emulsion.

SAGD requires high quality (99 wt.%) steam vapor for injection into sub-surface wells to maximize the heat transfer. Higher quality steam increases the available latent heat of condensation when the injection steam vapor contacts the sub-surface steam chamber walls. This is the effective area where bitumen is mobilized via viscosity reduction due to increased temperature before gravity draining to a production well. Generally, the high-quality steam leaving the CPF, and transported via pipeline requires elevated pressure [~10 MPa(g)] to ensure the steam, can be moved at high quality to the adjacent SAGD well pads for distribution to various injection wells.

An example of the Block Flow Diagram (BFD) of a generic SAGD operational scheme can be found in Appendix A.

4. Generic Site Operation Characteristics

For this report, a reference SAGD central processing facility (CPF) based on the Canada's Oil Sands Innovation Alliance (COSIA) SAGD Template (ML-WLS–OTSG)[8] has been adopted. As described in the COSIA SAGD reference plant report, this CPF reference case contains:

- Electric Submersible Pump (ESP) as the Mechanical Lift (ML) technology.
- Warm Lime Softening (WLS) for water treatment.
- Once Through Steam Generators (OTSGs) to meet steam production requirements.
- Power imported from the grid.

Operational characteristics of this 33,000-barrel (bitumen) per day facility have been assumed to require approximately 15,757 m^3/d Cold Water Equivalent (CWE) of steam (100 wt.%, 10 MPag, and 312°C) for a Steam-to-Oil (SOR) ratio of 3.00 (wet).

Generally, to achieve the high-quality steam, vertical separation vessels are used downstream of the natural gas boilers. This allows for an effective management of the low-quality steam condensate that contains entrained contaminants including elevated levels of chlorides, hardness, and silica. This boiler blowdown, or steam condensate, is cooled via heat integration to pre-heat the BFW prior to further cooling before being directed to deep well sub-surface disposal injection wells. It is assumed that the BFW is typically pre-heated to

8 COSIA SAGD Reference Facilities.

175°C via upstream inlet emulsion and produced water coolers before cross-exchange with the boiler blowdown. The final pre-heated BFW enters the steam generators at 195°C.The final steam produced from the existing boilers targets an 85 wt.% quality at 10 MPa(g) (312°C) prior to entering the high-pressure steam separator to produce the final high-quality steam (>99 wt.%) and blowdown for heat integration.

Therefore, SMR integration requires the following basis for consideration, assuming all steam is displaced, and the existing natural gas boilers are laid up and out of service:

- Final HP High Quality Steam to Field:
  - Flow: 15,757 tonnes per day
  - Pressure: 10 MPa(g)
  - Temperature: 312°C
  - Steam Quality: >99 wt.%.

This basis is consistent with a thermal duty of approximately 362 MW_{th} required from SMRs. It is also assumed that for this same basis, up to a maximum of 18 MW_e is required for back-door power demand to be generated by SMR integration to meet the existing site load demand of the generic 33,000 bbl/d SAGD facility.

5. Siting Assessments for Nuclear Power Facilities

5.1 Overview

Site selection and characterization for nuclear reactors in Canada is a crucial, early step in the successful development of SMRs. Like many large, capital intense developments in the energy sector, site-specific criteria influencing the social, technical (engineering, environmental, etc.), and regulatory feasibility of a project must be identified and understood from a variety of stakeholder perspectives, and continually re-evaluated throughout the project's lifecycle. This ongoing assessment of risks and opportunities, while scanning for emerging issues, is a commonly used approach for numerous industries and is the basis for Hatch's methodology used herein. The use of nuclear energy benefits from this same practice and has an elevated level of scrutiny inherent in being among Canada's most highly regulated industries. This section provides key principles and general considerations that are consistent with national and international standards used in site characterization studies.

5.2 Methodology

There are two important, technically oriented viewpoints guiding siting assessments for nuclear power reactors: (1) understanding the role and effects site-specific characteristics can play in the safe operation of a nuclear facility, as well as (2) potential effects a facility can have on the surrounding environment (including safety-related aspects of the human environment). For licensing, only safety-related aspects are considered by the regulator; although a key, non-technical / non-safety viewpoint that addresses social considerations, such as public acceptance, must be addressed by proponents to ensure successful development. This section is focused on technical and regulatory feasibility considerations.

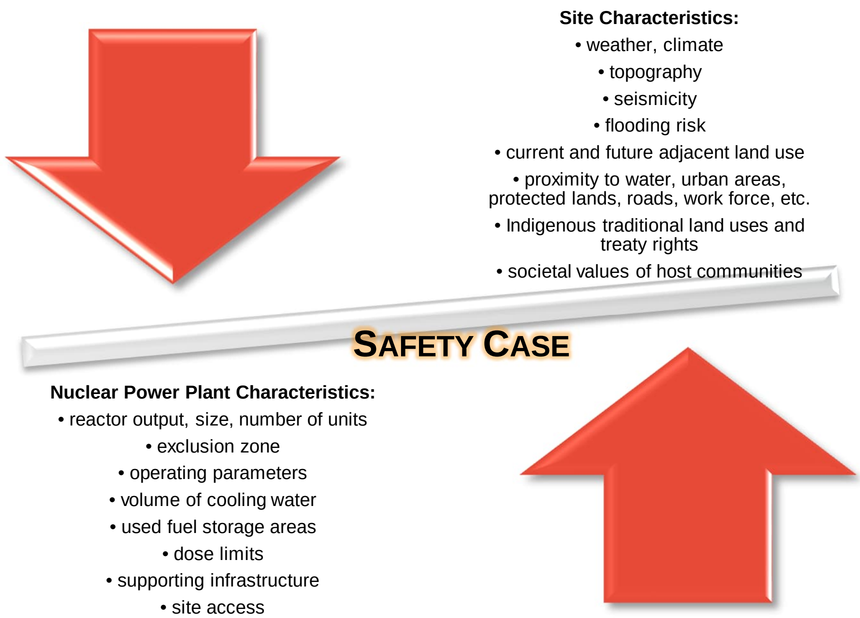


Figure 5-1: Canadian Nuclear Safety Commission's View of a Safety Case

In Canada, there are no prescriptive regulations dictating the suitable attributes of a location for hosting a nuclear power reactor. Instead, the Canadian regulatory framework is risk-informed, relying on a (prospective) licensee's ability to demonstrate that all activities needed to prepare a site, construct, operate and eventually decommission a reactor can be safely carried out under existing and anticipated conditions, and that there are no unmanageable risks to both the external environment and the reactor facility at a host location. This concept is considered the "safety case" and is central in describing activities regulated by the Canadian Nuclear Safety Commission (CNSC).

The International Atomic Energy Agency[9] (IAEA) offers pragmatic guidance and best practices to work through a structured siting assessment process for nuclear power facilities. The IAEA calls upon on Member States, which includes Canada, to utilize these safety standards as broadly and effectively as possible, and in recent years, has reiterated that Member State authorities (e.g., governments, regulatory bodies) pay close attention to the implementation of IAEA safety standards during siting assessments by private sector. In addition to the IAEA, the CNSC provides guidance on evaluating sites for new reactor facilities and utilizes a graded, or risk-based approach to siting that includes small reactor facilities. Through the IAEA, members can access support in establishing a robust safety case for new nuclear facilities, with the aim of establishing a process for site characterization

[9] The IAEA is global, coordinating intergovernmental organization that seeks to promote the peaceful use of nuclear energy and to inhibit its use for any military purpose. Canada is a Member State of the IAEA.

and selection for nuclear power plants. IAEA guidance[10] recommends that site suitability be evaluated according to the following principles:

1. The effects of external events occurring in the region of the particular site (these events could be of natural origin or human induced).
2. The characteristics of the site and its environment that could influence the transfer to persons and the environment of radioactive material that has been released.
3. The population density and population distribution and other characteristics of the external zone in so far as they may affect the possibility of implementing emergency measures and the need to evaluate the risks to individuals and the population.

Site-specific attributes that influence these principles must be thoroughly identified and described, and their effects on the facility (or other licensed activities such as site preparation) must be fully understood. In developing a safety case, licensees must demonstrate that a host location meets fundamental safety objectives that protect people and the environment. If no engineering solutions or other adequate control measures exist to protect against hazards, a site should be deemed unsuitable for hosting a nuclear installation.

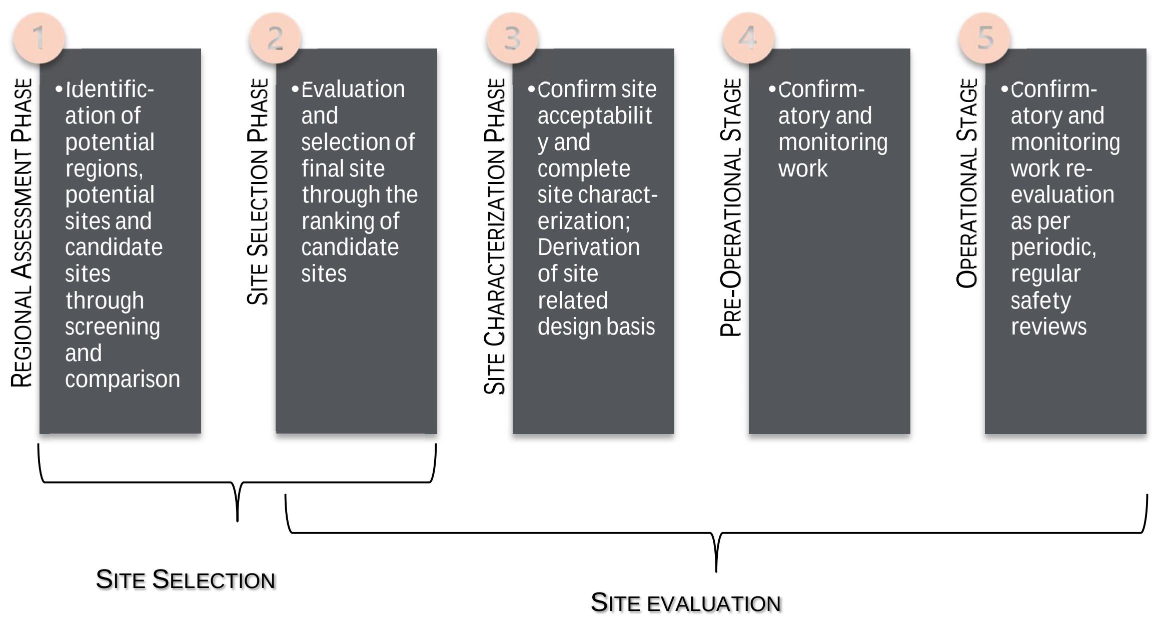


Figure 5-2: IAEA's Site Assessment Process

Site preparation, construction, and operation phases all rely on location-specific information collected using rigorously controlled methods that are ultimately governed in a nuclear licensee's management system. All information should be collected and stored in a systematic, transparent, repeatable, and well-documented manner. Both site characterization

10 IAEA, 2019. Site Evaluation for Nuclear Installations, Specific Safety Requirements, SSR-1.

and the methodology used to collect the data must be established early in the development phase for a nuclear power plant and will be continually evaluated over the life of the facility. Having a robust process for identifying and characterizing site attributes, ideally with input from all critical stakeholders, is best established early in the siting assessment phase, and can support a successful project that prepares organizations for licensing under the CNSC.

5.3 Siting Process and Criteria

The steps to selecting a nuclear power plant site on the basis of safety should be considered using three predominant types of criteria: regional, exclusionary and discretionary. These criteria are identified and tested throughout the siting process to survey for and select a suitable location; this is one of the defence in depth elements advocated by nuclear energy regulators worldwide including the CNSC. Understanding the site's suitability within the broader geographical region can help to ensure alignment with local government mandates, and subsequent candidate sites should be further assessed by screening them against safety and non-safety related (i.e., economic, social) considerations. Once a site is selected, criteria are monitored and regularly re-evaluated during the operating life of the installation. This section provides a brief overview of these categories and how they might be applied in gauging suitability of sites for a small reactor.

5.3.1 Regional Criteria

Regional considerations that could affect the suitability of an area for hosting a nuclear power plant generally relate to national, provincial, and local/municipal government mandates and are not necessarily directly relevant to the Client's traditional or historical use of an area. Regional considerations are also outside the realm of influence, or direct control of a [prospective] licensee due to their broad nature. For this reason, regional criteria may not have been included in the Client's previous site assessments for current SAGD facilities.

Regional criteria could include considerations around national security and proximity to provincial or international borders, Indigenous communities, domestic policies on economic development, national and international commitments to environmental protection, future developments and land use planning, long-term urban growth and expansion, and the availability of shared resources such as transportation routes, cooling water and other infrastructure considerations. General physical characteristics of a region, such as topography or seismicity, can also be included in regional assessments but are not limited to this category.

Because these are outside the typical purview of a private sector organization, it is critical that relevant levels (municipal, provincial, federal) and types of governments (First Nations, Métis Nations) be advised and consulted early of a proposed nuclear power plant. This will support the aim of understanding regional factors that could influence site suitability, which, as noted, may not have been previously considered when siting existing oil and gas developments.

For candidate sites, regional considerations should be directly informed through government engagements and consultation as needed. Because existing facilities could be considered for deployment of co-located SMR technologies, regional considerations can be addressed during the subsequent site characterization phases where both fatal flaws and other non-critical attributes of an area are studied.

5.4 Exclusionary Criteria

Conditions that preclude a candidate site from hosting a nuclear reactor are assessed by applying a go/no-go analysis. Exclusionary criteria can include both safety and non-safety related considerations, however for application to the SAGD facility, these criteria are more likely to focus on safety-related features of the biophysical environment that could preclude the safe construction and operation of a nuclear power plant at the existing SAGD installations. In contrast, and to provide an example, in the United Kingdom, the government has applied a policy of siting new nuclear plants in areas where the population density does not exceed certain thresholds, and where the growth of that population can be monitored and controlled. The application of this exclusionary demographic criteria during site selection is independent of the detailed safety assessment that is undertaken as part of the UK's regulatory review and approvals process, although confirmation that the demographic criteria continue to be met is sought as part of this assessment[11]. A similar approach of establishing thresholds that are not directly used to develop the safety case, but nonetheless important in delivering a successful SMR project, can be taken in Alberta as part of the Client's siting process.

These types of go/no-go criteria provide the basis for discarding sites that are unacceptable due to existing environmental conditions, phenomena, and hazards, whether naturally occurring or anthropogenically created, for which there are no practical and cost-effective engineering, site protection, or administrative solutions. Both present and future phenomena must be equally considered, as the site could be operating for many decades.

5.5 Discretionary Criteria

Conditions that do not disqualify, but can have a wide-ranging influence on the feasibility, acceptability, and cost of SMR deployment at a site, are known as discretionary. These criteria reflect conditions, phenomena, issues, events, etc., for which cost-effective protective engineering solutions or administrative measures exist to ensure a robust safety case is established.

Discretionary criteria are typically applied in an iterative fashion to assess and rank the suitability of candidate sites and ultimately identify a preferred site. For the Client's interest, the majority of criteria used to assess SAGD sites for co-locating an SMR will be discretionary. The IAEA's screening criteria are outlined below and consist of both safety and non-safety related conditions.

[11] Office for Nuclear Regulation, 2018. Land Use Planning and Siting of Nuclear Installations, NS-LUP-GD-001, Review Date: July 2022. Accessed February 8, 2023.

Table 5-1: IAEA-Derived Screening Criteria for Site Selection10

Criteria		Category	
Primary	**Type**	**Screening**	
		Exclusionary	**Discretionary**
Volcanism	Lava flow	✓	
	Pyroclastic flow	✓	
	Ground deformation	✓	
	Tephra fall		✓
	Volcanic gases		✓
	Lahars (massive)	✓	
Flooding	River		✓
	Dam break		✓
	Coastal (storm surges, waves, etc.)		✓
	Tsunami		✓
Extreme meteorological events	High straight winds (plow winds)		✓
	Tornadoes		✓
	Tropical storms		✓
	Precipitation		✓
	Sand, dust storms		✓
Human induced events	Aircraft crashes		✓
	Explosions		✓
	Gas releases		✓
	External Fires		✓
	Electromagnetic interference		✓
Nuclear security events			✓
Dispersion	In air and water		✓
Feasibility of implementation of emergency plan		✓	
Implementation of emergency plan			✓
Non-safety	Topography		✓
	Availability of cooling water	✓	✓
	Access to water		✓
	Availability of transport		✓
	Access to national or regional electricity grid		✓
	Non-radiological environmental impacts	✓	✓

Criteria		Category	
Primary	Type	Screening	
		Exclusionary	Discretionary
	Socioeconomic impacts		✓
	Land use planning		✓

Engineering design must incorporate site-specific characteristics such as extreme weather events and the type and volume of available water (as deemed necessary) to ensure effects will not impede the external environment occurring in the region of a particular site.

6. Generic SAGD Facility Selection Guide

As an initial screening for considering the evaluation of integrating SMR technology, with SAGD facilities, a decision tree selection tool was developed. The purpose of this tool provides a high-level roadmap to determine if certain criteria are met to assist evaluating the SMR deployment integrated with thermal in situ oil sands operations.

See Appendix C for the Generic SAGD Facility SMR Integration Decision Tree Selection Tool.

As a reference to the integration of SMR technology with a generic SAGD facility, a Block Flow Diagram (BFD) (Appendix B), Process Flow Diagrams (PFDs) and Heat & Material Balance (H&MB) table are provided in Appendix D through Appendix E.

7. Overview of SMR Technology

This section provides an overview of SMR technology to provide a common basis of understanding used in the assessment of vendor designs and integration considerations addressed in later sections. SMRs are nuclear fission reactors that are smaller than conventional nuclear reactors with typical electrical power outputs of less than 300 MW_e. They are designed to have a higher percentage of components and modules factory manufactured and transported to site for installation compared to traditional nuclear power plants. The deployment of multiple SMRs per site is promoted to reduce on-site construction, and through the economics of multiples[12], ultimately reduce cost and deployment risk. SMR designs range from adaptations of existing nuclear power plant designs to new and emerging designs representing significant departures from water-based reactor technologies. These designs include molten salt, sodium, and gas cooled reactors.

[12] The concept of economy of multiples is related to the multiplier effect in economics. The multiplier effect refers to how much an initial investment can stimulate the wider economy over and above the initial amount.

7.1 Nuclear Reactor Technology Overview and Vendor Listing

7.1.1 Nuclear Reactor Technology Generations

Nuclear reactor technology is divided into technology "generations" which describe in broad terms the technological basis of the reactor design. The existing light and heavy water nuclear power reactor fleet is generally comprised of Generation II and III nuclear reactors. SMRs are being developed along two different nuclear reactor technology generations: Generation III+ and Generation IV.

Generation III+ reactors refer to advanced water-cooled reactor designs being adapted for the SMR market. This includes PWRs, IPWR's, PHWRs, and BWR's. Gen III+ also includes very large reactors that have been developed more recently, such as CANDU 6, AP1000 and EPR. These designs typically represent an evolution of existing utility-class designs that leverage advances in technology to provide a reactor design that increases passive safety and provides a cost advantage compared to Generation III designs.

Table 7-1: GEN III+ Design Goals

GEN III+ Design Goals[13]
A more standardized design for each type to expedite licensing, reduce capital cost and reduce construction time.
A simpler and more rugged design, making them easier to operate and less vulnerable to operational upsets.
Higher availability and longer operating life – typically 60 years.
Further reduced possibility of core melt accidents.
Substantial grace period, so that following shutdown the plant requires no active intervention for (typically) 72 hours.
Stronger reinforcement against aircraft impact than earlier designs, to resist radiological release.
Higher burn-up to use fuel more fully and efficiently and reduce the amount of waste.
Greater use of burnable absorbers ('poisons') to extend fuel life.

Generation IV reactor designs are more novel in approach and, while they may have some operational history, they tend to be significantly less widely deployed than their Generation III counterparts. Generation IV nuclear reactor categories have been designated by the Gen IV International Forum (GIF); an international organization dedicated to the development of advanced nuclear reactor technologies. Design Goals associated with Generation IV reactors are summarized in Table 7-2.

[13] https://world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/advanced-nuclear-power-reactors.aspx#:~:text=So-called%20third-generation%20reactors%20have%3A%201%20A%20more%20standardised,reduced%20possibility%20of%20core%20melt%20accidents.%2A%20More%20items.

Table 7-2: Generation IV Reactor Design Goals14

Category	Design Goal
Sustainability	Generation IV nuclear energy systems will provide sustainable energy generation that meets clean air objectives and provides long-term availability of systems and effective fuel utilization for worldwide energy production.
	Generation IV nuclear energy systems will minimize and manage their nuclear waste and notably reduce the long-term stewardship burden, thereby improving protection for the public health and the environment.
Economics	Generation IV nuclear energy systems will have a clear life-cycle cost advantage over other energy sources.
	Generation IV nuclear energy systems will have a level of financial risk comparable to other energy projects.
Safety & Reliability	Generation IV nuclear energy systems operations will excel in safety and reliability.
	Generation IV nuclear energy systems will have a very low likelihood and degree of reactor core damage.
	Generation IV nuclear energy systems will eliminate the need for offsite emergency response.
Proliferation Resistance and Physical Protection	Generation IV nuclear energy systems will increase the assurance that they are very unattractive and the least desirable route for diversion or theft of weapons-usable materials and provide increased physical protection against acts of terrorism.

7.1.2 Nuclear Reactor Technology Descriptions

Various reactor technologies exist and are under development. SMR designs that are currently under development include designs in the following technology categories:

- Boiling Water Reactors (BWR)
- Pressurized Water Reactors (PWR)
- High Temperature Gas-cooled Reactors (HTGR)
- Sodium Fast Reactors (SFR)
- Lead Fast Reactors (LFR)
- Molten Salt Reactors (MSR)

[14] The Generation IV International Forum, "Generation IV Goals," 2020. [Online] Available: https://www.gen-4.org/gif/jcms/c_9502/generation-iv-goals [Accessed 21 December 2022].

7.1.2.1 *Boiling Water Reactors*

Boiling Water Reactors (BWRs) have a single circulating loop that circulates water into the reactor core to directly produce steam. This steam is then transported directly to a turbine generator to produce electricity before being condensed back into water and sent back to the reactor core. In a BWR, the reactor directly replaces the boiler in the Rankine cycle, rather than heating the working fluid indirectly as in all other reactor designs.

BWRs have extensive operating experience from around the globe. The GE-Hitachi BWRX-300 selected for deployment at Ontario Power Generation's Darlington New Nuclear Project[15] is based off GE-Hitachi's other BWRs[16]. This will allow operating experience to be leveraged from BWR nuclear power plants both operating and decommissioned in other jurisdictions such as the United States, Japan, and Germany.

7.1.2.2 *Pressurized Water Reactors & Pressurized Heavy Water Reactors*

Pressurized Water Reactors (PWRs) and Pressurized Heavy Water Reactors (PHWRs) work by using a pressurized, sub-cooled water primary coolant loop to carry heat away from the reactor core. This hot water is transported to a steam generator and used to turn water from a secondary loop into steam before being transported back to the reactor core. The steam produced in the secondary loop drives a steam turbine to create electricity, afterwards it is condensed before cycling through the process again.

Many modern, smaller (~< 200 MWe) PWRs are classified as Integral-PWRs (IPWRs), meaning that most key components are contained in a single, sealed transportable unit. IPWRs are an evolution of the conventional large Pressurized Water Reactors and fundamentally leverage the same heat generation and core cooling methods as PWRs. In IPWRs not just the reactor core but most other major components including the steam generators are enclosed inside a single, modular vessel. This IPWR design characteristic offers the potential to eliminate some potential accidents initiators (e.g., large loss of coolant accidents (LOCAs), control rod ejection accident), decrease the probability of failure for remaining initiators, and mitigate some consequences.

PWRs are the most common type of nuclear reactor with large operating fleets in the United States, France, and other countries. PHWRs such as the CANDU rector are widely deployed inside Canada with operating plants in several other countries as well.

7.1.2.3 *High Temperature Gas Reactors*

High Temperature Gas Reactors (HTGR) are a type of Generation IV reactor that use gas (typically helium) at high temperatures as a coolant. High pressure helium is circulated through the reactor core before passing through a heat exchanger where it is used to heat up a secondary fluid to produce electricity or process heat. The helium is then repressurized and pumped back through the core to continue to cycle.

[15] https://www.opg.com/media_releases/opg-advances-clean-energy-generation-project/.
[16] https://nuclear.gepower.com/build-a-plant/products/nuclear-power-plants-overview/bwrx-300.

All the HTGRs engaged in the CNSC Vendor Design Review (VDR) process (see Section 11.1) use TRISO fuel, though in varying configurations. TRISO fuel is manufactured by surrounding a small quantity of uranium fuel with layers of carbon and ceramic to provide a robust, high-temperature barrier to the release of fission products (see Section 7.2.2 for additional details). Based on the characteristics of TRISO fuel, it is generally accepted as one of the most robust nuclear fuels from a safety perspective.

The two typical HTGR reactor core configurations are prismatic block and pebble bed. Prismatic block features a core comprised of large pieces of graphite with many coolant channels. TRISO fuel particles are then distributed throughout the core, close to the coolant channels. Pebble bed reactor cores typically consist of a near cylindrical container filled with spherical pebbles approximately the size of billiard balls. These pebbles are composed of TRISO particles in a graphite matrix. The key functional difference between the two core configurations is that prismatic block reactors must be shut down and refueled at regular intervals while pebbles can be added and removed continuously from a pebble bed, allowing for on-line refueling.

Several jurisdictions throughout the world have experience with HTGRs:

- Germany's 46 MWth, pebble-bed AVR operated from 1966-1988.[17]
- An 842 MWth, prismatic-block reactor operated at Fort St. Vrain in the USA from 1979-1989.[17]
- Japan currently operates a 30 MWth prismatic block reactor.[18]
- South Africa invested $1.3 billion in the development of the Pebble-Bed Modular Reactor (PBMR) before the program was terminated.[19]

The UK also has extensive experience with gas-cooled reactors through both helium-cooled (Dragon) and CO2-cooled (Magnox and AGR) designs.

7.1.2.4 Liquid Metal Fast Reactors (Sodium/Lead)

In contrast to the reactors discussed previously which use water or graphite to moderate neutrons to slow speeds, fast reactors are designed to maintain their neutrons at high energies (approximately 1 MeV). By operating in the fast neutron spectrum, fast reactors can increase the energy yield from their fuel compared to thermal reactors. The fast neutron spectrum also allows these reactors to burn spent fuel. This enables the possibility to use current stockpiles of spent nuclear fuel for operation. This will in turn both reduce the quantity of spent fuel and increase the average rate at which it decays. However, there are political challenges associated with fuel re-processing that must be addressed before being adopted in a power reactor design. Additional care also needs to be included in the reactor design to

[17] https://www.nrc.gov/docs/ML0219/ML021960037.pdf.
[18] https://www.jaea.go.jp/04/o-arai/nhc/en/faq/httr.html.
[19] https://www.world-nuclear-news.org/NN-PBMR_postponed-1109092.html.

address the differences in dynamics and control between thermal neutron and fast neutron reactors.

Sodium Fast Reactors (SFRs) use molten sodium metal as the reactor coolant to remove heat from the reactor core through a sodium-sodium heat exchanger. The sodium within this secondary sodium coolant loop is transported to a second heat exchanger where it is typically used to generate steam from water and then generate electricity. Lead fast reactors (LFR) are similar to SFRs but use lead as a coolant. Due to the differences between lead and sodium, there are different implementation risks between the two reactor types that drive differences in the vendor designs.

Several SFRs have operated as commercial power/research reactors[20]:

- Russia has operated the BN-350, BN-600 (600 MWe) and most recently the BN-800 (880 MWe) reactor.
- Two CFR-600 (600 MWe) reactors are under construction in China.
- The USA has operated several SFRs, the largest of which (Fermi 1) produced 200 MWth from 1963 to 1975.
- The UK operated the 250 MWe PFR from 1974 to 1994.
- France constructed several SFRs, culminating in the 3000 MWth Superphénix reactor that operated sporadically from 1986 to 1997.

LFRs were used in the Soviet Alfa class submarines of the 1970s with the reactors in the OK-550 and BM-40A designs both capable of producing 155MWth. Russia has LFRs currently under development including the SVBR-100 (280 MWth) and the BREST-300 and BREST-1200. Lead-cooled reactor operation and development has a very limited history outside of Russia.

7.1.2.5 Molten Salt Reactors

Molten salt reactors (MSRs) refer to a category of reactor that uses liquid salt to remove heat from the reactor core. Many different designs exist that include large pool-type fast-spectrum reactors, graphite moderated circulating-fuel reactors, and pebble-bed salt-cooled reactors. They are commonly categorized by whether the fuel is dissolved in the salt and circulates in and out of the core or whether the fuel is contained within the core and cooled by a molten salt. Reactors using fluoride salts and reactors using chloride salts are being developed with both types typically operating between 600°C to 700°C at near atmospheric pressure.

The MSR was conceived of in the 1940's and was the leading candidate design for use in aircraft propulsion due to its high temperature and low weight. The Aircraft Reactor Experiment (ARE) proved the MSR concept viable, it was then cancelled, and the focus shifted to civilian use, resulting in the development of the Molten Salt Reactor Experiment (MSRE) at Oak Ridge National Laboratory (ORNL). This circulating fuel, graphite moderated

[20] https://www-pub.iaea.org/MTCD/Publications/PDF/Pub1489_web.pdf.

MSR operated for 4 years in the 1960's. The program was eventually cancelled and MSR development stagnated. However, interest has since renewed and there are many designs progressing through development and commercialization, though much of the recent development is inspired by and built-upon the previous work from ORNL.

7.1.2.6 *Other Reactors*

Gas-cooled fast reactors (GFRs) are similar to thermal spectrum HGTRs in that they operate at similar temperatures and often use a helium coolant. The main difference is that they operate using a fast neutron spectrum and typically use a non-TRISO, more fissile fuel. The only GFR currently undergoing significant development is ALLEGRO, a 100 MWth demonstration reactor, being developed by several European countries. No true gas-cooled fast reactor design has ever been operational.

All reactors discussed so far use a (typically pumped) fluid circulating in a loop to remove heat from the core, the other competing alternative for heat removal is heat pipes. They are heat transfer devices with no mechanical moving parts that transfer heat by making use of the energy associated with evaporation and condensation. The basic principle is that a working fluid evaporates in the core, travels to the cold sink, condenses and returns to the core by way of gravitation or capillary action. Though heat pipes are much more effective than solid conductors, they are not able to transport nearly as much heat as a pumped fluid.

7.2 Nuclear Fuel

Each SMR technology uses slightly different fuel forms to produce heat in their reactor cores. Two fuel forms, TRISO and metal fuel are discussed, but others have been proposed including various molten salt mixes where one of the components is UF_4 or UCl_3. Uranium dioxide (UO_2) in the form of fuel pellets is used in traditional nuclear power reactors. While the water-cooled SMRs considered in this study use UO_2, more novel fuels have been proposed for use in the majority of the other reactor (Gen IV) designs.

7.2.1 *Enrichment*

Naturally occurring uranium consists of two isotopes: U-238 (99.3%) and U-235 (0.7%). Out of the two isotopes, U-235 is used for energy production as it is a fissile material—a material capable of sustaining a nuclear fission chain reaction. Enrichment refers to the process of increasing the amount of U-235 in uranium to make it more suitable for use in a nuclear reactor.

Almost all commercially deployed nuclear reactors in operation or under construction utilize uranium that has been enriched, with the notable exception being the CANDU reactor. The level of enrichment is generally between 3 and 5%, the most widely employed enrichment level is 4.95%, the upper limit of low enriched uranium (LEU). Modern small and GWe-scale BWR and PWR reactor designs typically specify an enrichment at or near 4.95%. The level of enrichment is dependent on the type of reactor and the specific requirements of the nuclear power plant operator (e.g., refueling cycle period).

Commercial reactors are limited to an enrichment level of 19.9% which is governed by international agreements. Fuel enriched between 5% and 19.9% is called high assay LEU (HALEU). Currently HALEU's availability is limited in Western countries. However, new facilities are in development to provide additional supply sources outside of the traditional supply chain provided by Russia. Because commercial BWRs and PWRs generally do not use fuel in excess of 4.95% enrichment, they are able to leverage existing fuel supply chains for their fuel needs.

7.2.2 TRISO Fuel

Tri-structural isotropic (TRISO) fuel particles are a form of Accident Tolerant Fuel (ATF) comprised of small particles that have five distinct regions.

At the centre of the particle is the fuel kernel that contains the nuclear fuel (either uranium, plutonium, thorium, or transuranic elements) in the form of either an oxide, carbide, or oxycarbide. The most common material used for TRISO fuel kernels is UO_2 but, in some reactors, UCO can be used instead depending on the desired characteristics. The kernel is contained within a porous, carbon buffer then surrounded by an inner pyrolytic carbon (IPyC) layer followed by a silicon carbide (SiC) layer. Together these layers provide multiple barriers against fuel failure and act as a pressure vessel for the particle, providing a diffusion barrier that prevents the release of both gaseous and metallic fission products. The final, fifth layer is the outer pyrolytic carbon layer (OPyC).

As a result of the layered design, TRISO particles are more structurally resistant to neutron irradiation, corrosion, oxidation, and high temperatures compared to traditional nuclear fuels. With each particle acting as its own containment system with tolerance to very high temperatures, TRISO particles will not melt – even under accident scenarios. TRISO fuel is very versatile and has been proposed for use in multiple reactor types including MSRs, HTGR's, and Heat Pipe reactors. Regardless of the fuel and moderator configuration, the use of TRISO fuel results in an increased safety margin compared to existing reactors.

There is limited production of and operating experience with TRISO fuel. As noted, this currently poses a supply concern as there is no large-scale TRISO production operation in place. However, there are various plans underway to scale up production:

- USNC has a pilot production line in Oak Ridge, Tennessee.[21]
- In 2021 Canadian Nuclear Laboratories produced TRISO fuel for the first time.[22]
- BWXT recently began production of TRISO.[23]

[21] https://www.usnc.com/fuel/.
[22] https://www.world-nuclear-news.org/Articles/TRISO-fuel-made-in-Canada-for-first-time.
[23] https://www.bwxt.com/news/2022/12/07/BWXT-Starts-Production-of-TRISO-Fuel-for-First-US-Generation-IV-Microreactor#:~:text=In%20addition%20to%20TRISO%2C%20BWXT,agency%27s%20Space%20Technology%20Mission%20Directorate.

- X-energy recently broke ground on a commercial-scale TRISO fuel fabrication facility that is expected to be operational by 2025.[24]

Coated particle fuel was first developed for the Dragon Reactor in the UK in the 1960s, and follow-on gas reactors in Germany, the United States, Japan, South Africa, and China have used TRISO fuel.

7.2.3 Metal Fuels

Metal fuels are an alternative fuel form that consists of a fissile metal (like uranium) being alloyed with other metals to produce a solid metal fuel. Solid metal fuels provide for a higher density of both fissile and fertile materials and have a much higher conductivity than traditional ceramic UO_2. The primary concern with traditional metal fuels is a lower melting temperature compared to oxide fuel (UO_2). Metal fuels tend to be favoured for use in fast reactors where they have benefits such as an enhanced ability to burn actinides and allowance for a more compact core.

8. Deployment Scenarios: Development and Trade-Offs

To evaluate how each of the SMR technologies or technology classes may interface with an existing SAGD operation, several different deployment scenarios have been developed and are presented in this section. While several deployment scenarios have been presented, it is noted that there are many different viable designs for the interfacing facility between an SMR and a SAGD operation, not all of which have been discussed in this report.

In the design of the interfacing facilities in this section, considerations such as radiological protection, thermal storage, and reliability must be evaluated. For the purposes of this study, the deployment configurations adopt the following assumptions presented in Table 8-1.

Table 8-1: Assumptions for Deployment Scenario Development

Assumption	Basis
Steam pressure losses to and from the reactor site are negligible	Expected to be a short distance relative to the distance from the main steam header to the injection sites and the flow would be through large bore pipes.
Heat losses from heat transport fluids to the environment are negligible	Impact on economic viability and configuration selection is minimal. High heat flows relative to surface area.
Natural Gas as a backup power supply option is acceptable.	Can provide significant cost saving with relatively little carbon emissions.

[24] https://x-energy.com/media/news-releases/triso-x-breaks-ground-on-north-americas-first-commercial-advanced-nuclear-fuel-facility.

Assumption	Basis
SMRs that cannot fully heat the SAGD process steam to a high enough temperature can be supplemented by either an additional heat supply (natural gas, hydrogen, or other fuels) or by steam compression.	Water-cooled designs which operate at lower temperatures are compelling because of the technological basis and regulatory and design progress in jurisdictions of interest.
The integration of the SMR with the SAGD site will provide at least three (3) layers of protection between the nuclear fuel and the SAGD steam.	Refer to Section 8.1.1 on Radiological Protection. Assumption to be validated during regulatory engagement and licensing.

8.1 Common Considerations

While some of the deployment considerations in interfacing an SMR with a SAGD facility are specific to the SMR technology selected, many considerations are generic in nature and are related more broadly to the integration of nuclear technology into a SAGD environment. The following subsections outline significant considerations that may:

- Impact either the design of the interfacing facility between the SMR and SAGD plant.
- Influence the siting process of the SMR at the SAGD facility, or
- Influence the technology selection process at a given deployment location.

Broadly, engineering and siting solutions can be adopted during the project development to address each of these solutions. While this report does not specifically adopt recommendations to address each of these items in a specific deployment scenario, the deployment scenarios described later in this section are developed to address these items.

8.1.1 Radiological Protection & Interfacing Facility Design

Nuclear energy systems are designed to have multiple layers of protection to prevent radioactive particles from entering the biosphere. Radiological Protection is a greater concern in the production of SAGD steam compared to electricity generation because of the possibility that radioactive particles released into the injection steam could spread throughout a large area underground rather than just traverse an enclosed power generation loop. To ensure a sufficient level of separation between the nuclear fuel and the SAGD process steam, at least three layers of protection are, at this stage, assumed to be necessary, though this will require validation through regulatory licensing.

In the context of this study, an intermediate loop is defined as a heat transport loop introduced between the SMR and the SAGD facility that is separate from the process steam (or heat transport fluid) being provided by the nuclear island. For deployment configurations where an intermediate loop is needed to address radiological separation concerns, Solar Salt has been adopted as the intermediate fluid composition. Molten salts, and in particular Solar Salt, has been selected as the intermediate fluid because it is unreactive, chemically stable, is not considered a health hazard, does not need to be held under pressure, and has favorable heat transport qualities. In the design of an intermediate loop, either a high or low-pressure intermediate loop may be acceptable. For a high-pressure loop, the intermediate fluid will flow into the reactor coolant in the event of a breach. For a low-pressure intermediate loop, SAGD process steam would flow into the intermediate loop in the event of a breach. The potential flow of primary coolant into a low-pressure intermediate loop is of limited concern, since it cannot flow further into the high-pressure SAGD process steam.

The following provides a discussion of the layers of radiological separation for each SMR technology type along with an assessment of whether the addition of an intermediate loop may be required.

- **PWR/IPWR:** The 3 barriers are recognized to be the fuel cladding, the reactor coolant to the intermediate fluid heat exchanger (or steam generator), and the OTSG. An additional intermediate loop is not required.
- **Metal-cooled:** Most metal-cooled SMRs are being designed to include multiple layers of separation to ensure safe operation with the chemically reactive or toxic metal coolant as well as radiological separation of utility and process steam generation. Therefore, from a radiological protection standpoint, the introduction of an additional intermediate loop is generally considered unnecessary, though it will depend on the specific reactor technology being deployed.
- **Gas-cooled:** TRISO fuel is generally regarded as providing better radiological protection than fuel in light water reactors and may be considered on its own to have several layers of protection. Although an intermediate loop may not be required to achieve adequate protection, given the lack of operating experience with TRISO fuels, the inclusion of an intermediate loop has been adopted in this study, and an additional intermediate loop is certainly not required.
- **Molten salt based:** There are a wide variety of MSRs using a variety of fuels and fueling approaches as well as salt compositions. Several MSR designs incorporate a solar salt loop between the nuclear island and turbine. For this style of reactors, an additional interface loop would not be required, and heat for SAGD applications could be taken from the solar salt loop. Other designs may need to be assessed on a case-by-case basis but, generally, the design of MSRs is such that the introduction of an additional intermediate loop is not likely to be required.

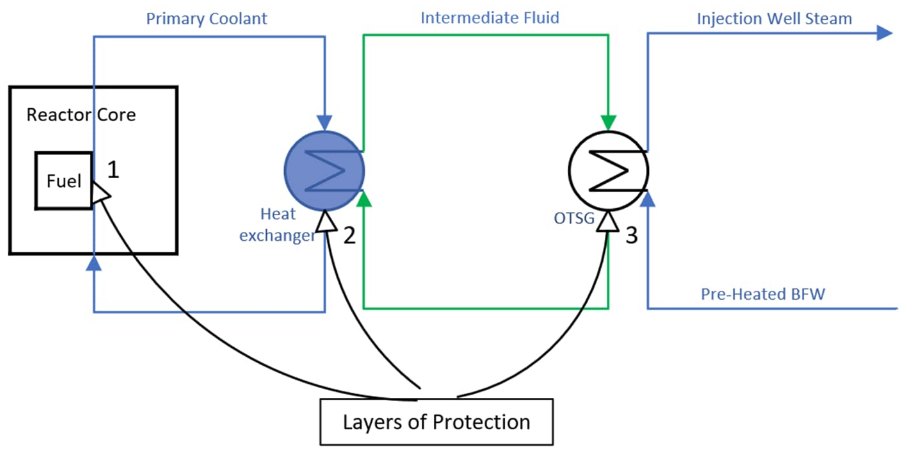


Figure 8-1: Layers of Radionuclide Protection

8.1.2 *Reliability Considerations*

The importance of reliability of SAGD steam production is critical for the use of an SMR in this application. The SMR deployment configuration should eliminate or minimize downtime to always ensure continuous steam production.

Reactor downtime arises from either planned outages, which consist of regular maintenance and refueling outages, or unplanned outages, which result from a variety of potential causes. Each SMR design may ultimately differ in the delivered capacity factor (uptime) to a site; however, at this stage reliability data is difficult to validate as SMRs do not have a significant operational track record, even though many of the technologies that SMRs are based on do.

In a SAGD facility, steam demand is rarely reduced to zero during operational periods. Depending on the facility, maintenance outages every few years may provide an opportunity to align SMR maintenance outages and SAGD plant outages. To maintain as close to 100% uptime during operational periods as possible, several means of enhancing the reliability of an SMR deployment through the design of the interfacing facility have been identified as follows.

1. Introduction of significant thermal energy storage (e.g., large salt tanks, see Section 8.1.3).
2. Oversizing of the Nuclear Deployment for steam production.
3. Sizing the SMR facility for significant electricity production with the ability to transition electrical units to steam production to provide backup power as needed.
4. Providing a non-nuclear backup power solution (e.g., natural gas). In a brownfield application existing OTSGs and/or natural gas co-generation units will already be available for backup, while in a greenfield application it may not be advantageous to purchase backup natural gas units.

While the solution selected for a given deployment will be site specific, Option #3 is preferred from a deployment perspective as it allows all the installed SMR capacity to be used productively when available (either for heat or power). However, the feasibility of this option is dependent on the ability to connect and be paid for power provided to the grid. It also introduces some complexity to the design of the interfacing facility. Alternatively, the use of a non-nuclear backup power solution (e.g., natural gas) may be attractive economically, but results in a solution that may not meet net zero emissions goals for the facility.

The number of SMRs (units) deployed at a site will also impact reliability. An assessment was completed to approximately quantify the reliability of reactor deployments where SMRs are used in a combined heat and power environment. This assessment highlights the probability that SAGD steam production is forced to decrease below the design basis. This would occur when more reactors are out of service than the number required to meet the electricity production capacity. Assumptions for this assessment include:

- For this assessment, the timing of the downtime is randomly assigned and independent of other reactors.

  Note: this assumption is recognized to be incorrect due to the planned nature of refueling and large maintenance outages. However, this assumption is considered sufficient for this illustrative example.

- An assessment assuming two to four SMR modules at a site was completed.
- The sample calculations are performed with a capacity factor (SMR availability) assumed to be 95%. The variable *U* is the uptime and *n* is the number of units. *The number of SMR units for SAGD steam* (column #2, Table 8-2) is assumed to cover a set site SAGD steam production demand, the fewer the number of units, the larger each individual unit.

As an example, the probability of reduced SAGD steam production, if three SMR modules are deployed, two for process steam and one for electricity, is as follows. SAGD steam production is reduced only when two or more reactors are down and the unit generating power cannot compensate for the reactors out of service:

- $P_{unavailable} = 1 - (prob. all\ units\ operational) - (prob. 1\ unit\ down)$
  - $P_{unavailable} = 1 - (U^n) - (n \cdot (1 - U^n) \cdot (U^{n-1}))$
  - $\geq 2\ units\ down = 1 - (0.95^3) - \left(3 \cdot (1 - 0.95) \cdot (0.95^{3-1})\right)$
  - $\geq 2\ units\ down = 1 - 0.8574 - 0.1354$
  - $\geq 2\ units\ down = 0.0073\ (0.73\%).$

For example, if four SMR modules are deployed, two for process steam and two for electricity production, SAGD steam production is reduced only when 3 or more reactors are down and the two units generating power cannot compensate for the reactors out of service.

- $P_{unavailable} = 1 - (P, all\ units\ operational) - (P, 1\ unit\ down) - (P, 2\ units\ down)$
  - $P_{unavailable} = 1 - (U^n) - \left(n \cdot (1-U) \cdot (U^{n-1})\right) - \frac{n!}{(n-2)!2!}(1-U)^2 \cdot (U^{n-2})$
  - $\geq 3\ units\ down = 1 - (0.95^4) - \left(4 \cdot (1-0.95) \cdot (0.95^{4-1})\right) - 6(1-0.95)^2 0.95^{4-2}$
  - $\geq 3\ units\ down = 1 - 0.8145 - 0.1715 - 0.0135$
  - $\geq 3\ units\ down = 0.00048\ (0.05\%)$.

Table 8-2 lists the probability of reduced SAGD steam production as a function of the number of SAGD steam and electricity producing reactor units as well as the reactor capacity factor (reactor uptime). The probability of a total loss of SAGD steam is also included. Note that this calculation is very sensitive to the independence assumption which may not be true in all deployment scenarios. From the results in the table, it is noted that for a given SAGD steam demand and electricity capacity, reliability is enhanced by having a greater number of units deployed.

Table 8-2: Probability of Reduced SAGD Steam Production

Reactor Uptime	# SMR Units for SAGD Steam	# SMR Units for Electricity	Probability of Reduced SAGD Steam	Probability of Total Loss of SAGD Steam[25]
90%	1	1	1.00%	1.00%
90%	2	1	2.80%	0.10%
90%	2	2	0.37%	0.01%
90%	3	1	5.23%	0.01%
95%	1	1	0.25%	0.25%
95%	2	1	0.73%	0.01%
95%	2	2	0.05%	0.00%
95%	3	1	1.40%	0.00%

In general, SMRs deployed to support SAGD operations are suggested to be deployed in a combined heat and power environment which will allow electrical generating units to cover for outages of the primarily heat producing units. The deployments of a larger number of SMR modules may also enhance reliability by providing a higher redundancy in the number of units producing electricity which could be redirected to serve process heat needs during planned and forced outages.

[25] Note: This calculation assumes that all failures are independent which will not be valid under all deployment scenarios. A formal system reliability analysis should be performed to confirm system reliability during the design process.

While the use of natural gas as a backup may be feasible, there are integration challenges that need to be considered. This includes where the natural gas heaters/boilers are introduced into the system and how they will be operated. Potential carbon-emissions in this scenario would need to be assessed against corporate net zero targets to ensure this approach remains compliant with emissions targets.

8.1.3 Thermal Energy Storage

The addition of Thermal Energy Storage (TES) to the deployment configuration allows the reactor power and steam demand to be decoupled. This helps to isolate the SMR from changes in steam demand or process upsets which can be absorbed with the thermal energy storage system.

While these advantages are discussed in terms of the use of thermal energy storage, it should be noted that they can also be met using thermal controls applied to an interfacing steam loop. An assessment of the advantages and disadvantages of both approaches requires specific knowledge not only of the design of the end use process facility (in this case SAGD), but also of the frequency, magnitude, duration, and impact of potential process and power upsets on the functioning and economics of production.

There are several potentially viable thermal storage mechanisms and two in particular have been considered:

- **Latent heat thermal storage:** Latent heat thermal storage uses a Phase Change Material (PCM) to store latent heat. To charge the thermal store, a high-temperature intermediate fluid heats the PCM causing it to melt. To discharge the thermal store, the PCM transfers heat energy to the cold fluid as it solidifies.

  For SAGD applications, potential PCMs include molten salts or metal alloys. However, given the scale of this application, metal alloys can be ruled out due to their high cost.[26]

- **Specific heat thermal storage:** Specific heat thermal storage is the heat energy that is stored in a material as it changes temperature. Specific heat can be stored in the intermediate fluid itself (if molten salt is adopted) or in a low-cost filler material such as concrete, clay bricks, or even rocks. Specific heat thermal storage is compatible with any intermediate fluid and any temperature range. The technology is substantially more developed than other TES mechanisms, the challenge, especially for a system without filler material, is of cost.

  - For the volume required, Molten Salt (MS) is expensive ($800/ton, $1,388/tonne CAD 2023[27]) and would require the deployment of hot and cold molten salt storage tanks. Depending on the amount of heat to be stored, this may require the construction of a significant tank farm as the thermal storage demand of a SAGD facility is significant if it is to be carried over any significant outage duration.

[26] https://www.sciencedirect.com/science/article/pii/S2666386421002514.
[27] https://www.researchgate.net/publication/331993959_Concentrating_Solar_Power_Gen3_Demonstration_Roadmap.

The challenges with using latent heat thermal storage or adopting specific heat thermal storage with a filler material are expected to result in higher overall costs than the use of molten salt storage tanks. Concentrated Solar Power (CSP) installations regularly face a very similar TES storage choice. Most installations choose to include thermal storage and choose to do so using the specific heat of MS (salt tanks). If TES is to be applied to an SMR deployment at a SAGD operation, the specific heat of MS is suggested over other TES alternatives. A schematic of a potential deployment with TES provided by salt tanks is shown in Figure 8-2.

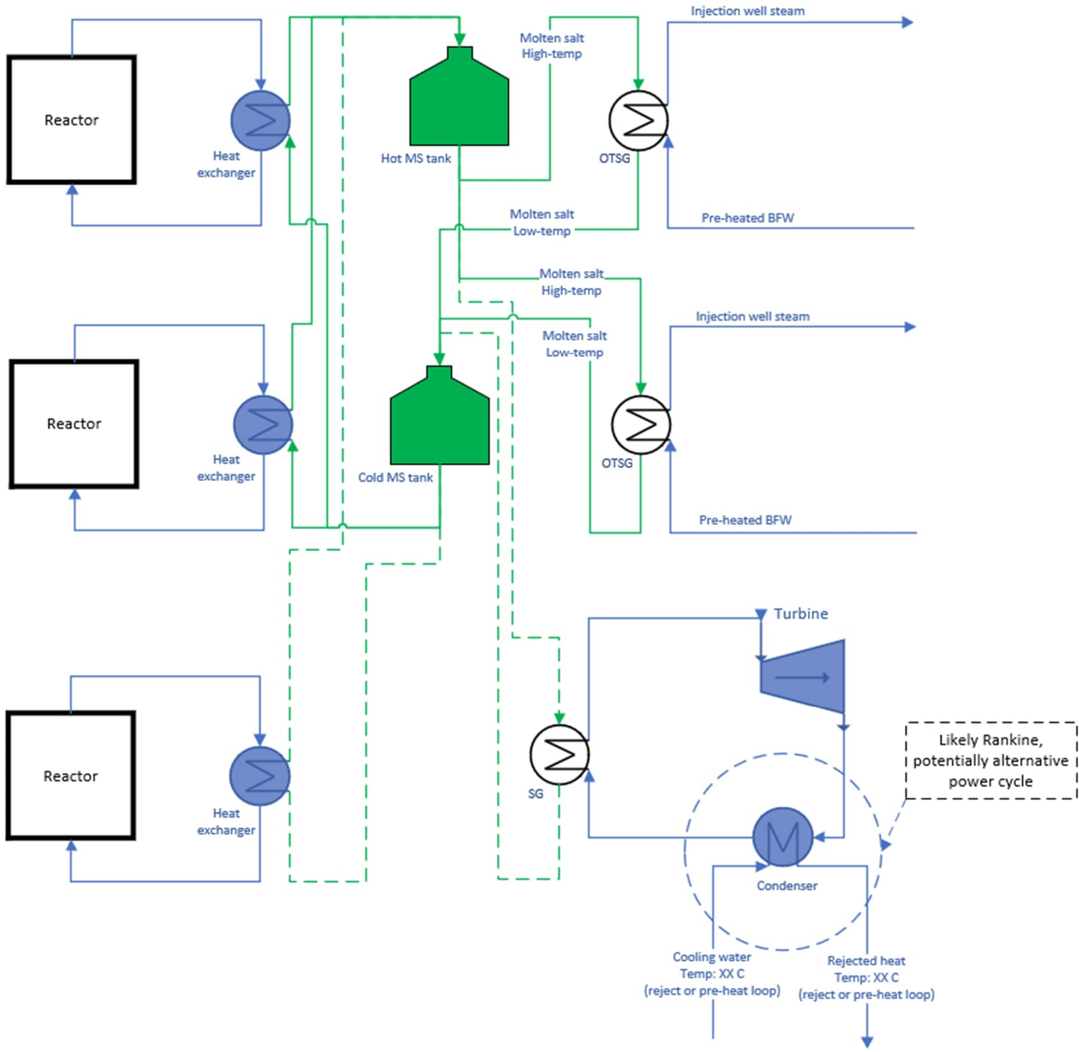


Figure 8-2: Thermal Energy Storage Using Molten Salt Tanks

8.1.3.1 *Thermal Energy Storage Period*

Molten salt storage to provide SAGD heat production for three weeks is explored. The reason for this timeframe is to cover PWR refueling time and scheduled maintenance. PWR refueling periods are typically 18 months to 24 months rather than 1 year, but 3 weeks every 1 year is taken as the reference case to account for a portion of maintenance outages (planned or unplanned) in addition to refueling.

The cost estimate shown below is for a MS heat storage system with a 290°C low temperature tank and a 565°C hot tank from a 2019 National Renewable Energy Laboratory (NREL) report.[28] The cost of Solar Salt in the CSP industry is $700-800/ton shipped to the U.S, as per a key supplier. The report cites a salt melting cost of $50 per ton. The size of the salt tanks, total salt inventory, and the overall system costs are as follows:

- Hot Tank - Stainless Steel 11,900 m^3.
- Cold Tank - Carbon Steel 10,800 m^3.
- Salt inventory (includes heel) – 27,400 tonnes.
- TES, $/kWh-t: $22 (USD, 2018). Equal to $34.50/kWh-t CAD, 2023.[29]

Cost estimates of long-term TES and natural gas backup are compared in the following calculations:

3 MW-weeks of TES: A two-tank MS storage system for this deployment would not be able to have as large a temperature range as the NREL report, so the cost estimate is performed with a 165°C range instead: $57/kWh ($57,000/MWh) · 3 weeks (504 hours) = <u>$28,728,000/MW</u> (for 504 hours or 3 weeks of full-power storage).

- Three weeks of thermal storage would require 504 MWh/MW of steam production.

Natural Gas (NG) backup: Estimated cost: <u>~$300,000/MW</u> (N.G. + capital equipment)

- The cost of a backup OTSG plus installation is assumed to be $100,000/MW (CAD 2023). This estimate based on past Hatch research and an INL study[30].
- The cost of NG and a $170 carbon price in 2030 is assumed to be ~$11/MMBTU ($37/MWh), additional maintenance costs are ignored. If NG backup is used for 3 weeks per year it would cost ($37/MWh·24 hr/day·21 day/year) $18,648/year/MW.
  - The $18,648/MW annual NG cost is assumed to be equal to a present value of approximately $200,000/MW.

Given this extreme difference in cost, storage capacity beyond a few hours should not be considered. Specifics of the nuclear technology used and detailed integration with SAGD

[28] Turchi, Craig S., Boyd, Matthew, Kesseli, Devon, Kurup, Parthiv, Mehos, Mark S., Neises, Ty W., Sharan, Prashant, Wagner, Michael J., & Wendelin, Timothy. *CSP Systems Analysis - Final Project Report*. United States. https://doi.org/10.2172/1513197.
[29] Inflation 2018 to 2023: 15%, 1.00 USD = 1.37 CAD.
[30] https://art.inl.gov/NGNP/NEAC%202010/INL_NGNP%20References/TEV-704%20Nuclear%20Assisted%20Oil%20Sands%20Rec%20via.pdf.

processes are yet unknown. Storage on the order of 20 minutes to provide a buffer from minor load variations is likely advantageous. Storage in the order of 6 hours to provide the ability to generate more electricity at periods with a high electricity pool price is likely uneconomic but should be explored further in subsequent work.

8.1.4 Nuclear Exclusion Zone Boundary

As defined by the Canadian Nuclear Safety Commission:

> *"An exclusion zone is an area surrounding a nuclear facility that is under the control of the licensee and is generally intended to reduce individual and societal risk from nuclear power plants."* [31]

As this area is controlled by the licensee, development activities within, and access to, the exclusion zone are generally limited.

There are no pre-determined or prescriptive regulatory requirements for exclusion zone and emergency planning zone (EPZ) sizes in Canada. Historically in Canada, exclusions zones have been set at 1,000 yards (914 m) from the reactor building. However, current practice dictates that they are established using a combination of dose limits, security and robustness design considerations, meteorological conditions and emergency preparedness considerations that are affected by the land use around the site.[32] In other words, the size of an exclusion zone and EPZ is based on the risk posed by the reactor design and characteristics of the site. Several SMR vendors expect to have an exclusion zone of ¼ mile (approximately 400 m) while others have proposed an exclusion zone located at the fence boundary to the facility. Given the regulatory uncertainty in exclusion zone sizing, adopting a 400 m exclusion zone during the planning for an initial SMR deployment at a SAGD facility is suggested.

Inside of an exclusion zone, the reactor site structures should not overlap with the location of any existing infrastructure (power line, steam lines, pads, etc.). While external infrastructure may be able to remain within an exclusion zone, the amount of infrastructure should be minimized due to challenges to accessibility and maintainability. Having natural features, such as streams and lakes, inside the exclusion zone is not expected to present an issue to licensing so long as they are appropriately assessed and protected through the site impact assessment.

In a SAGD deployment, the SMR should be located far enough from the existing SAGD facilities that significant portions of the existing operation do not fall within the exclusion zone. However, various utilities will need to cross the boundary between the SMR site and the

[31] Allison, N., Cormier, K., Morin, C., & Schwarz, G. (2018, 07 26). *Overview of the Historical and Regulatory Basis for Exclusion-Zone Sizing in Canada*. Retrieved from Canadian Nuclear Safety Commission: https://nuclearsafety.gc.ca/eng/resources/research/technical-papers-and-articles/2018/overview-of-the-historical-and-regulatory-basis.cfm?pedisable=true.

Canadian Nuclear Safety Commission. (2022, February). *REGDOC-3.5.1, Licensing Process for Class I Nuclear Facilities and Uranium Mines and Mills, Version 2.1.* Retrieved from Canadian Nuclear Safety Commission: https://www.cnsc-ccsn.gc.ca/eng/acts-and-regulations/regulatory-documents/published/html/regdoc3-5-1-v2-1/index.cfm.

SAGD facility including steam and condensate lines which will need to be considered when defining the battery limits of the SMR facility.

8.1.4.1 Emergency Planning Zone

In addition to the Exclusion Zone, an Emergency Planning Zone would exist around any SMR.[33] Currently, it is unclear what the EPZs would look like for a SAGD deployment. EPZs are established by the province/territory and are under control of the region or municipality, as per CNSC's REGDOC-1.1.1.[34]

Considerations include, population density, population distribution (including of vulnerable populations) and physical characteristics that could impede the development and implementation of emergency plans. The EPZs are not expected to have a meaningful impact on the reactor site selection.

8.2 Deployment Scenarios

While the common considerations discussed in Section 8.1 can be considered applicable to all SMR technologies, the design of the interfacing facility between the SMR's nuclear island and the SAGD facility will vary depending on several design characteristics of a candidate SMR. For this study, the following characteristics have been used to categorize the different deployment environments:

- Reactor Technology: Generation III+ (water-cooled) or Generation IV (high temperature).
- Presence of an appropriate intermediate loop for radiological separation in the standard design.
- Number of SMR modules to be deployed based on the size of the SMR module compared to the deployment environment.
- Use of the SMR in a heat-only or co-generation (heat and power) setup.

Table 8-3 summarizes the six deployment configurations investigated for this study. Subsequent discussion on each of the deployment configurations is presented later in this section.

[33] Morris, Jim; Kennedy, John;. (2021, June). Validation of the Emergency Planning Basis for the Bruce Power Site. *00*. Ontario, Canada: Kinectrics. Retrieved from https://www.brucepower.com/wp-content/uploads/2021/06/ValidationBruceEmergPlanning.pdf.
[34] http://www.nuclearsafety.gc.ca/eng/acts-and-regulations/regulatory-documents/published/html/regdoc-1-1-1/index.cfm#sec3-3.

Table 8-3: Deployment Configurations

#	Reactor Coolant	Intermediate Loop	No. of Reactors	Heat-Only Setup	Co-Gen Setup
1	Water	Added in Interfacing Facility (Molten Salt)	1	See 8.3	See 8.3
2	Water	Added in Interfacing Facility (Molten Salt)	>1	See 8.3	See 8.3
3	High Temperature Coolant	Added in Interfacing Facility (Molten Salt)	1	See 8.4	N/A
4	High Temperature Coolant	Added in Interfacing Facility (Molten Salt)	>1	See 8.4	See 8.5.2.3
5	High Temperature Coolant	Included in Standard Design (Molten Salt or Steam)	1	See 8.4	N/A
6	High Temperature Coolant	Included in Standard Design (Molten Salt or Steam)	>1	See 8.4	See 8.5.2.3

To provide additional detail on each of the deployment configurations, block flow diagrams have been developed. For simplicity, blocks used to represent a reactor, heat exchanger or OTSG may represent a single, or multiple units. The following is a legend applied to all diagrams.

- **Dashed lines:** potential addition. It is unclear at this point whether the loop or equipment with dashed lines is required.
- **XX:** indicates unknown value.
- **"~":** indicates approximate value.
- **OTSG:** OTSG refers to a specific gas-fired steam generator. With nuclear heat the steam generator is not gas fired and OTSG is likely not the correct label. The label "OTSG" remains to distinguish it from other heat exchangers.
- Green flows represent the intermediate heat exchange loop. Molten Salt (MS) has generally been adopted in this study, but other heat transport fluids (e.g., steam, oil) may be appropriate depending on the deployment environment. Blue is assigned to all other flows.
- The black box indicates everything inside the reactor vessel. In some cases, this represents only the reactor core and connected coolant flows, in others it includes a heat exchanger from the reactor coolant to another fluid, either steam, salt, or metal.

In the BFDs, only major pieces of equipment, reactors, turbines/compressors, heat exchangers, etc. are shown. Emergency heat removal equipment, such as condensers as well as pumps and feedwater heaters in the power cycles are not shown as they are not necessary to understand differences in deployment configuration.

To address load variability, thermal energy storage may be adopted in each of the deployment scenarios, as described in Section 8.1.3. This allows short term process disruptions to be mitigated without requiring the SMR to change its power level. While the BFDs have been developed showing the use of a molten salt loop, a steam intermediate loop could make use of a bypass/dump condenser arrangement. In either case, the solutions are meant to address short duration variability while long duration outages would require a response from additional SMR units.

8.2.1 Reactor Technology

In this report, water-cooled SMR designs and high temperature SMR designs are investigated separately as different integration configurations and conditions will apply to each class of reactor technology.

8.2.1.1 Water-Cooled SMRs

Water-cooled SMR designs include Boiling Water Reactors (BWRs), Pressurized Water Reactors (PWRs), Integral Pressurized Water Reactors (IPWRs), and Pressurized Heavy Water Reactors (PHWRs). In developing the integration facility design, IPWRs are treated separately to PWRs & PHWRs as the reactor core and other major components including the steam generator are enclosed inside a single, modular vessel as shown in Figure 8-3. In deploying an IPWR for SAGD applications, the interfacing facility design only needs to consider the flow conditions outside of the integrated reactor vessel.

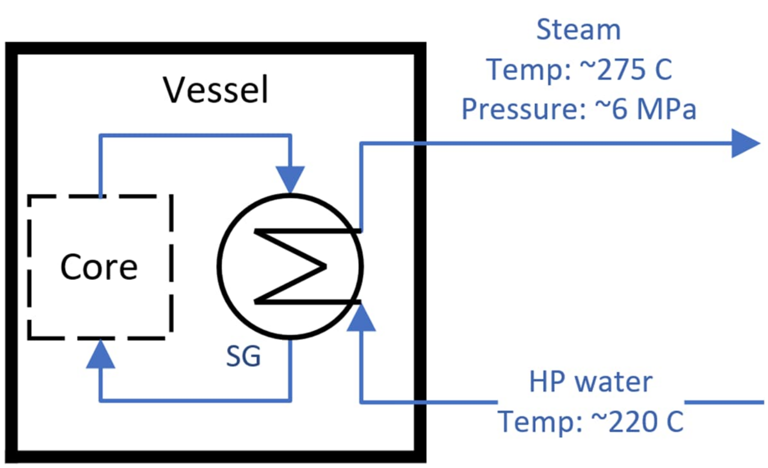


Figure 8-3: IPWR Basic Configuration Showing the Vessel Boundary

A summary of the design conditions for the steam produced by some of the PWR/IPWRs technologies under consideration are listed below in Table 8-4.

Table 8-4: Secondary Loop Steam Pressure of Water-Cooled Reactors

Reactor Tech.	Vendor/Design	Secondary Loop Steam Pressure (MPa)	Secondary Loop Saturation Temp. (°C)
PWR	Holtec	5.9535	275
IPWR	Nuscale	4.436	256
IPWR	SMART, KAERI	5.237	266

BWRs only have a single coolant loop. Water entering the reactor core is heated to generate steam, which is directly passed through a steam turbine to produce power. As this steam flow passes directly through the reactor core, it can become activated, which results in the activation of other components and presents challenges and added complexity for SAGD applications. Further discussion on the challenges related to the use of BWRs in a SAGD process steam application is presented in Section 9.2.2.6.

8.2.1.2 High Temperature

As a general category, Non-water-cooled designs feature primary core outlet temperatures high enough to allow direct coupling to the SAGD process. A summary of coolant outlet temperatures for high temperature reactors is provided in Table 8-5.

Table 8-5: Primary Coolant Temperature of High Temperature Reactor Technologies

Reactor Type	Range of Primary Coolant Temperature	Additional Comments
Gas-cooled	350°C - 850°C	Requires a large primary heat exchanger and/or a high temperature difference between the primary and secondary fluids because of the poor heat transfer properties of gases
Metal-cooled	350°C - 500°C	The two types of Liquid Metal Fast Reactors (LMFRs) are Sodium cooled and lead cooled. The liquid range of the two metals overlaps substantially and the thermal properties of the two liquid metals are similar.
Molten salt	600°C - 700°C	This type includes reactors with a salt coolant and/or reactors where the fuel is a liquid salt.

[35] https://www.neimagazine.com/news/newsholtecs-smr-160-nuclear-steam-supply-system-could-repurpose-coal-plants-10515567
[36] https://aris.iaea.org/PDF/NuScale-NPM200_2020.pdf.
[37] https://aris.iaea.org/PDF/SMART.pdf.

8.3 Water-Cooled Reactors: Heat-Only Configurations

This section summarizes Scenarios 1 and 2 from Table 8-3 associated with water-cooled reactors producing SAGD steam. While each specific water-cooled SMR design varies in output pressure and temperature, the scenarios presented in this section assume that an additional heat source is required to raise the temperature of the intermediate heat transport fluid to meet the SAGD process conditions. This may not be true for all reactor designs, in all deployment scenarios, and for all SAGD sites.

For the SAGD process in this study, most of the heat must be transferred through the OTSG to the BFW at the saturation temperature (312°C for the reference site with 10 MPa steam). Based on an average saturation temperature of the steam from water based SMRs of approximately 275°C, it is not possible to achieve the required injection well steam temperature without adding an additional source of energy to the system.

Using a PWR/PHWR, and adopting molten salt as an intermediate heat transport fluid, one possible deployment configuration involves replacing the primary-to-secondary steam generators with water-to-molten salt heat exchangers. This would allow the molten salt intermediate fluid to be heated further using natural gas or other means to meet the process conditions. Figure 8-4 summarizes this configuration.

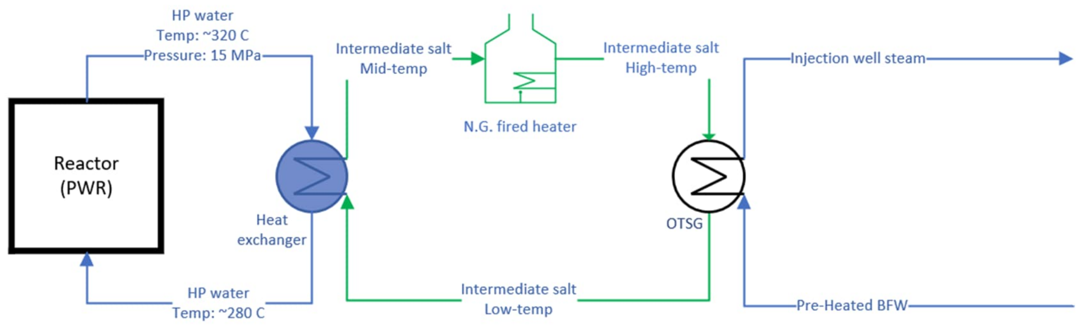


Figure 8-4: Water-Cooled SMR Deployment Configuration – External Heating

While this configuration is potentially viable, there are several challenges to consider. By replacing the primary-to-secondary steam generators with water-to-molten salt heat exchangers, a significant change is made to the SMR's standard plant design. This would require vendors to modify the nuclear island design and may result in significant impacts to licensing, deployment schedule, and cost. Vendors may also be unwilling to accommodate such a change.

To alleviate these concerns, an alternate deployment scenario involving the replacement of the molten salt loop with a steam loop, and the replacement of heaters with steam compressors has been investigated. Figure 8-5 shows one potential deployment configuration following this approach with the steam compressors located on the 'SAGD side' of the process.

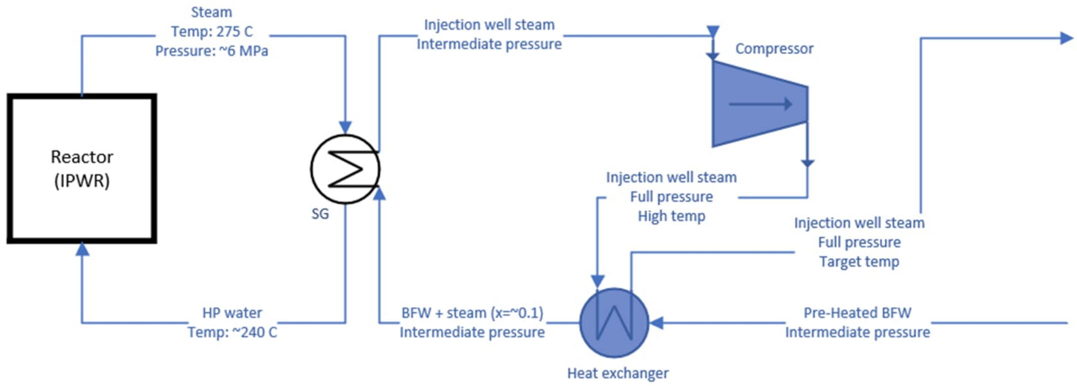


Figure 8-5: Water-Cooled Deployment Configuration - Steam Compression

The configuration shown in Figure 8-5 allows exclusively nuclear power (steam or electricity to power the compressor) to be used to meet the SAGD process conditions. This configuration places the steam compressor on the SAGD steam side to minimize the maximum steam pressure. However, situating the steam compressor on the SMR side of the plant is also possible which, would compress the steam in Figure 8-5 from ~6 MPa to ~14 MPa. The amount of additional nuclear energy (heat) generation required is calculated assuming the same SAGD steam conditions as the COSIA SAGD template.

In developing this configuration, locating the steam compressor on the SAGD side vs. the SMR side should be carefully evaluated. Trade-offs on the design of components on both sides of the heat exchanger will be required, and the optimal solution will be dependent both on the SAGD deployment environment and the SMR technology selected for use. Based on an initial market survey, steam compressors with the required throughput and pressure are also not widely available. This application is noted to be unusual in the market as high-pressure steam is traditionally generated in a boiler instead of being compressed from lower pressure steam. Highly compressing steam near its saturation conditions is also somewhat unusual.

Based on calculations using the COSIA SAGD reference facility, typical water-cooled SMR steam temperatures, and anticipated steam compressor performance, the integration of a steam compressor is anticipated to require approximately 32% more nuclear energy generation capacity than the energy transferred to the injection steam.

8.3.1 External Heating Options for Water-Cooled SMR Deployments

Figure 8-4 presents a water-cooled SMR deployment configuration using an external heater to increase the temperature of the intermediate fluid sufficiently to allow the SAGD process water to reach the necessary temperatures. In this section, three heating options are discussed.

8.3.1.1 Hydrogen

The most feasible means of carbon-free hydrogen production is electrolysis (either low- or high-temperature) where the majority of the energy input is electricity. Electrolysis is approximately 50% efficient in that the chemical potential of the hydrogen produced through electrolysis is equal to approximately 50% of the input electrical energy. Therefore, given that the suggested deployment configuration includes both heat and power, it is considered more efficient to use available electricity as the heat source directly, rather than to convert it to hydrogen first.

8.3.1.2 Electrical Resistance Heaters

The use of electric process heaters is likely the most economical, carbon-free heat source. Using electric heaters to raise the temperature of a molten salt at a large scale is a unique application but is likely not limited by the supply of the necessary equipment. Although a large process heater, designed specifically to withstand molten salt, could not be sourced during this study, several suppliers of industrial heaters designed to withstand high temperature, corrosive, and/or highly viscous liquids were found[38,39,40]. Moreover, given the relative straightforward design and manufacture of the required equipment, neither an array of process heaters in molten salt piping nor a modified salt tank deployment is expected to be a substantial impediment to a temperature-boosted deployment with an electrical heat source.

8.3.1.3 Natural Gas

Natural gas is likely the most economic option as a fuel for heating the intermediate fluid. However, as SMRs are being considered largely to support decarbonization plants, burning a significant quantity of natural gas to support the heating of the interfacing fluid may be incompatible with the broader deployment scenario supporting SMR integration with SAGD facilities.

Assuming that natural gas would be acceptable, it is presumed to be the most economical means of heating based on current and forecasted natural gas and electricity prices in Alberta. Natural gas is regularly used to heat a variety of fluids, including molten salts through the use of bath heaters[41] associated with solar thermal power plants. The supply of natural gas molten salt heating equipment has been briefly explored in this analysis, and it was found that, despite a very limited supply of equipment designed specifically for heating molten salts, no significant impediments to implementation were found.

8.4 High Temperature Reactors: Heat-Only Configuration

This section summarizes the deployment configurations investigated for High Temperature Reactors from Table 8-3. As with the water-cooled reactors, two heat-only scenarios have been developed: one without an intermediate molten salt loop and one with the introduction of an intermediate molten salt loop.

[38] https://www.chromalox.com/en/catalog/industrial-heaters-and-systems/process-heaters/custom-process-heaters.
[39] https://www.wattco.com/product_category/pipe-heater/.
[40] https://www.sigmathermal.com/products/electric-process-heaters/.
[41] https://www.sigmathermal.com/applications/molten-salts/.

Figure 8-6 presents a directly coupled configuration where the steam or molten salt from the SMR is directly coupled to the OTSG to generate injection well steam. This deployment configuration requires an SMR nuclear island design with sufficient separation between the reactor core and SAGD process steam as well as appropriate process fluid conditions from the SMR (either steam, molten salt, or otherwise) to allow the SAGD steam to reach the design conditions.

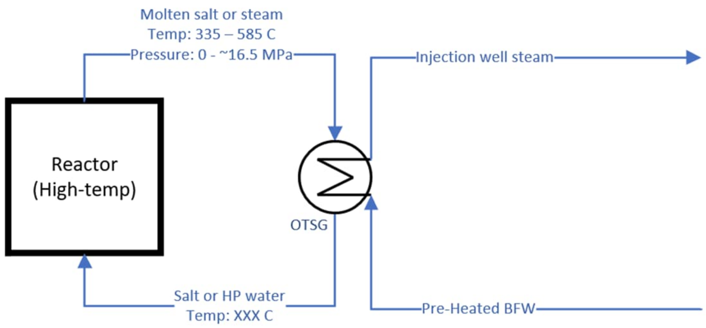


Figure 8-6: High-Temperature Deployment Configuration – Directly Coupled

This directly coupled configuration is preferable from a heat utilization and complexity perspective. Depending on the process fluid being provided from the SMR, thermal controls or energy storage may need to be introduced to limit the impact of process upsets.

Depending on the SMR technology and the need to isolate the process from the SMR either from a radiological standpoint or to limit the impact of process upsets on the nuclear plant operation, an intermediate loop – in this case consisting of molten salt – can be introduced between the SMR and SAGD facility. Figure 8-7 presents a BFD of this deployment configuration.

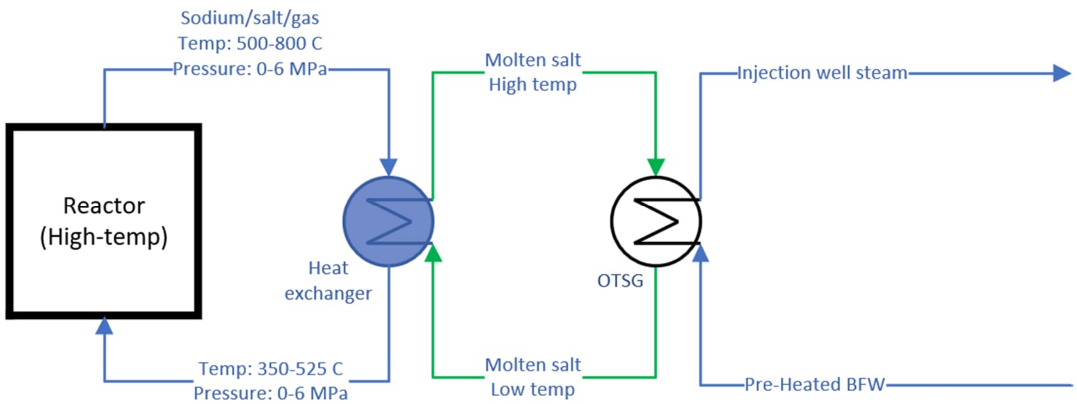


Figure 8-7: High-Temperature Deployment Configuration – Intermediate Loop

By adding or adopting an intermediate loop, the incorporation of thermal energy storage is simplified. However, the thermal efficiency of the system is reduced, and it represents a more capital intensive and complex deployment than the directly coupled system above. The decision to use a directly coupled vs. intermediate loop system will ultimately be driven by the SMR technology adopted for deployment and the requirements of the site.

In this scenario, only molten salt has been presented as an intermediate fluid. The use of high-pressure water is not viable due to the temperatures under consideration and steam, while potentially viable, has thermal properties that result in poor heat transfer and heat transport compared to liquids. Figure 8-6 and Figure 8-7 show the heat-only, high-temperature deployment configuration with one reactor and one OTSG unit, but it is intended to represent any number of reactor or OTSG units. The units would be tied together, combining in and outflows to a junction.

8.5 Co-Generation

Potential deployment scenarios where SMRs are used to provide both electricity and process heat for SAGD steam production are presented in this section. These scenarios may have significant variability in the electricity needs of a site, the net export of electricity to the grid, the total number of SMRs deployed at a site, and the number of SMRs assigned to generate electricity vs. process steam. These deployment characteristics are dependent on the economics of power production and export in each region, the site power demand, the site total output and demand for SAGD production, the economics of power production vs. electricity production, and the anticipated cost of the selected SMR design. Furthermore, for a given number of SMR units, capacity (output) and demand, there is also several feasible co-generation deployments.

In the following subsections, several different deployment scenarios are explored. Options for a decoupled solution are presented first, followed by options for coupled solutions. Commentary is provided on the assumptions made for each scenario as well as potential advantages/disadvantages.

8.5.1 Decoupled Co-Generation

In a decoupled co-generation scenario, separate SMR deployments are used for both heat production and electrical generation with no connection between them. Ultimately, different SMR technology options could be used to provide heat vs. electricity; however, due to the economies of multiples associated with SMRs, it is anticipated that the deployment of multiple units of a single technology would be beneficial at a single site. Figure 8-8 provides an illustrative diagram of this type of deployment. Note that, in this figure, a single SMR ‘block’ is shown producing both power and heat. In an actual deployment, multiple SMR reactor units may be present within this block.

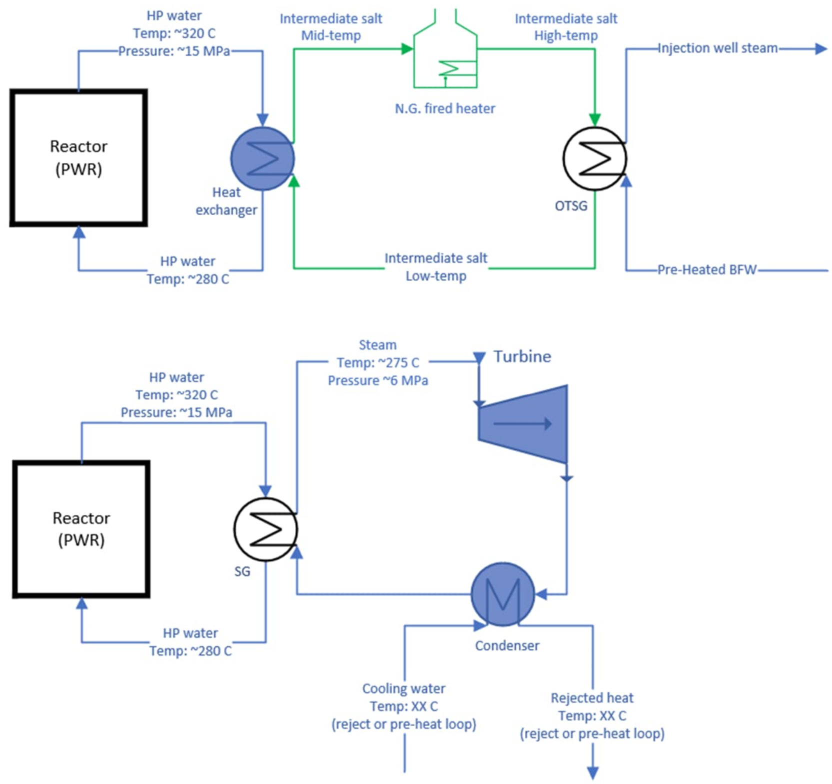


Figure 8-8: Decoupled Co-Generation Deployment

From an interfacing facility design standpoint, this type of approach is the least complex. Load balancing issues between steam and electrical generation are avoided as each set of SMR units is responsible for satisfying a given demand. However, there are a number of challenges associated with this type of deployment scenario.

- The thermal demand of a SAGD facility is generally significantly higher than the electrical demand. For the same SMR technology to be deployed for both heat and electricity production, either a significant net export position would need to be adopted from the facility, or the SMR module size would need to be aligned with the electrical generating needs of the facility which may lead to challenges in siting and implementation.
- By separating the heat and electricity generating units, any outages would need to be addressed using backup power or by restricting the production of steam or electricity. The ability to redirect units to cover for outages would not be possible.

Ultimately, while this deployment configuration is considered viable, the reliability and flexibility gained in coupling the heat and electricity generating units together is considered to outweigh potential drawbacks. The following subsections presents a number of potential deployment scenarios involving the deployment of coupled heat and power scenarios.

8.5.2 Coupled Co-Generation Scenarios

In the following scenarios, the SMR deployment (consisting of a single or multiple reactor units) is used to address both heat and power needs collectively. This is done through the use of one or more heat transport loops that directly connect each of the SMR units' output to heat exchangers providing both SAGD steam as well as electrical generation. While these configurations result in a more complex interfacing plant design than the decoupled generation scenario, they provide advantages in reliability by process steam production to be maintained through outages by 'redirecting' units supporting electricity production. While this approach requires validation with the electrical system operator, it allows for a higher degree of process steam reliability in a wider variety of configurations than is possible in a decoupled deployment scenario.

In these scenarios, it is assumed that the same SMR technology is used to support both process heat and electrical generation needs. As the heat generated by the SMRs can be flexibly dispatched to either heat or electricity production, matching the SMR unit sizes to both the exact heat and electricity production needs is less critical. Instead, the overall plant can be sized to meet the combined thermal power requirements for both steam production and electricity demand along with any agreed to net export position.

8.5.2.1 Series Primary Loop

In this scenario, the common outlet header from the SMR plant is connected to a heat exchanger for process steam supply and to a steam generator for electricity production in a series arrangement. Figure 8-9 provides a simplified block flow diagram of this configuration.

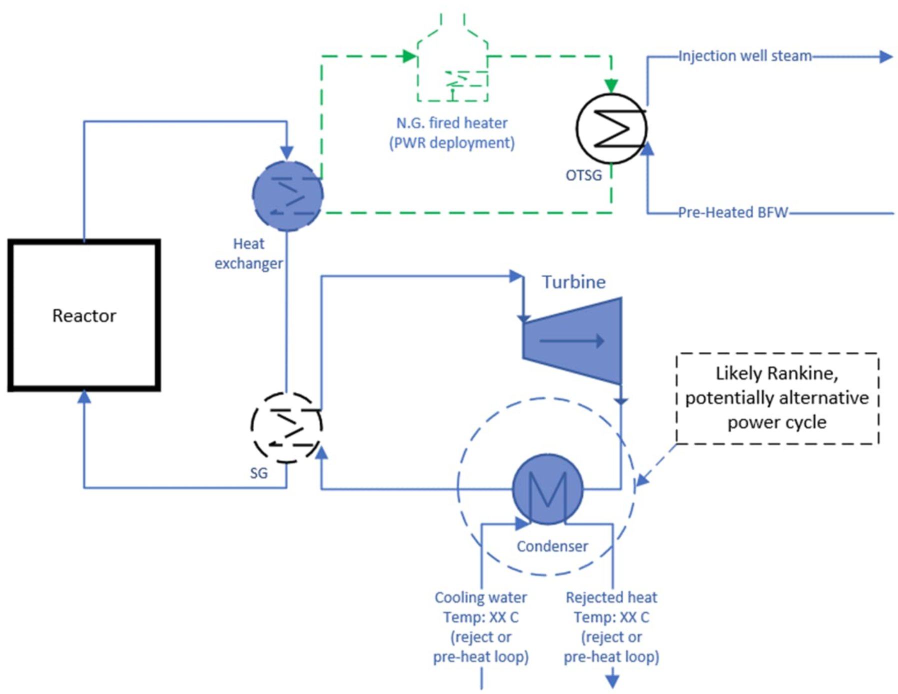


Figure 8-9: Coupled Co-Generation - Series Primary Loop

In Figure 8-9 the intermediate loop connected to the heat exchanger for process steam is shown in a dotted line, as it may or may not be required depending on the SMR technology under consideration and the proximity of the nuclear island to the SAGD integration point. Considerations related to shifting heat between electricity generation and SAGD steam production in this deployment scenario are listed below:

- The heat transfer surface area is fixed based on the design conditions of the deployment. However, as normal process fluctuations occur, or under upset or maintenance conditions, the heat transferred to either the process steam or electrical generation islands may need to be varied. This would be challenging to accomplish and would require the ability to significantly change the circulation velocity of the intermediate loop and/or working fluid which may not be practical.
- Utilizing excess heat for power production should the SAGD process demand be less than 100% is expected to be difficult to achieve. As the OTSG ramps down and power production ramps up, the average temperature of the primary fluid through the steam generator will increase. However, that alone is not anticipated to adequately increase power production.
    - The temperature of the power cycle working fluid through the SG is fixed at the saturation temperature. Reducing the system pressure to increase the temperature difference and heat delivered to the power cycle is considered to be challenging.

Given the challenges noted in this deployment scenario, implementation would require significant development work to investigate the range of operating scenarios, and potential incidences to ensure that the design of the system meets the intent of the coupled system to support higher reliability of steam production without introducing additional risks.

8.5.2.2 *Parallel Primary Loop*

In this scenario, the common outlet header from the SMR plant is connected to a heat exchanger for process steam supply and to a steam generator for electricity production in a parallel arrangement. Figure 8-10 provides a simplified block flow diagram of this configuration.

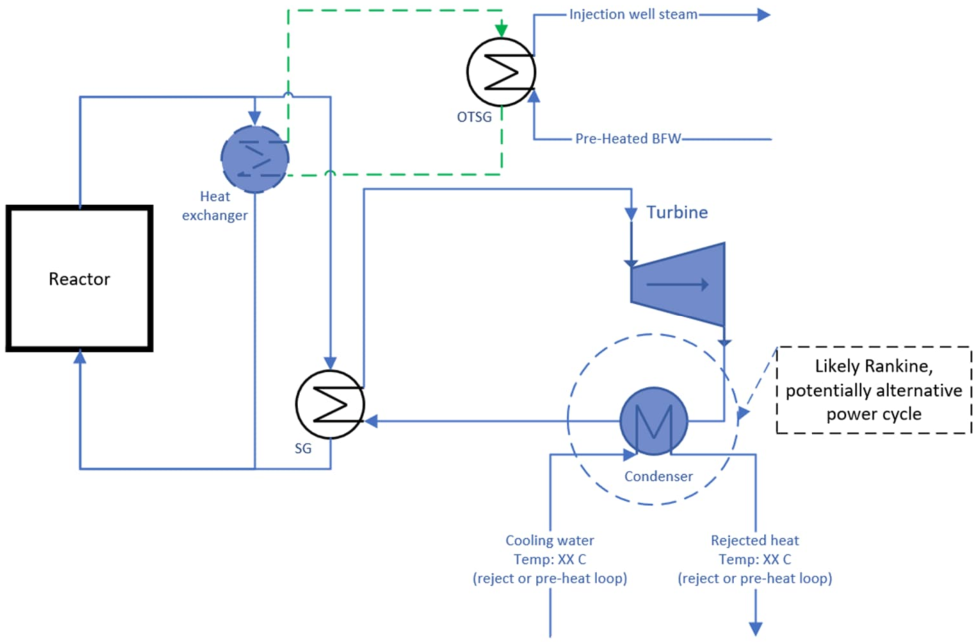


Figure 8-10: Coupled Co-Generation - Parallel Primary Loop[42]

This configuration is similar to Option 1: Series Primary Loop, the major difference being that the primary coolant loop splits into parallel streams, one for the heat exchanger and one for the steam generator.

- The heat transfer surface area is not necessarily fixed, multiple heat exchangers and/or SGs can be placed in parallel with only some in use at a given time.
- Variable power production control.
  - Major changes in the share of SAGD steam and power production are controlled by the number of heat exchangers/steam generators in use (in parallel).
  - Minor changes in the share of SAGD steam and power production are controlled by the primary coolant flow rate to the OTSGs/SGs.

[42] It is unsafe to add several piping junctions to configurations with reactor types that use high-pressure condensed coolant (PWRs). Therefore, it is assumed that this configuration does not apply to PWRs and so an intermediate coolant heater is not shown.

8.5.2.3 Combined Intermediate Loop

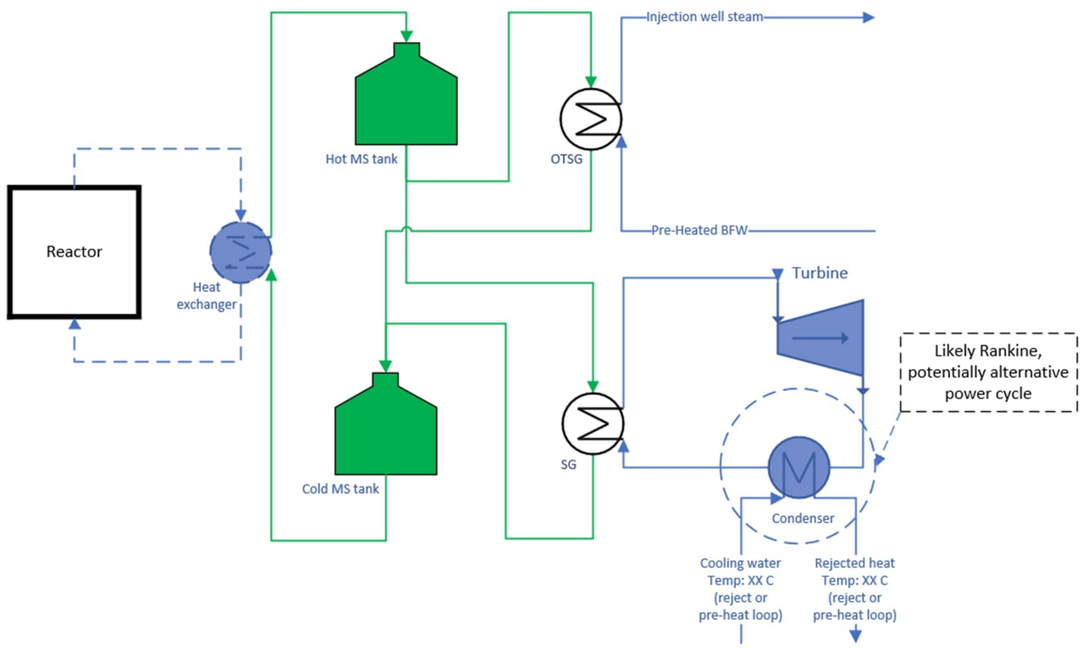


Figure 8-11: Coupled Co-Generation - Intermediate Loop

The inclusion of a combined (or common) intermediate loop allows for a high degree of flexibility between SAGD steam and electricity production. Figure 8-11 is shown for a high temperature reactor with an added molten salt intermediate loop but a PWR configuration or steam intermediate loop would be very similar. In the PWR configuration the only difference would be the inclusion of a MS temperature booster and a steam intermediate loop would not have TES tanks. The reactor design may generate steam at a pressure that exceeds the SAGD injection steam, in which case the steam would flow directly to the OTSGs and turbine without passing through a heat exchanger.

- The deployment scenario in Figure 8-11 shows a dashed primary loop and heat exchanger to indicate that only some reactor designs would result in a deployment that requires a heat transfer to the intermediate loop outside of the reactor.
- This deployment allows for full heat and power flexibility as long as the OTSGs and power cycles have the capacity to process 100% of the reactor power.
- A higher share of heat can be directed to either the OTSGs or the power cycle in one of two ways:
  i) The flow rate of the salt to the OTSGs/power cycle. The maximum SAGD steam production or power is limited by the summation of the thermal resistances OTSG/SG.

ii) The number of OTSGs/SGs connected to the flowing intermediate salt. Figure 8-11 only shows one OTSG and SGs but these represent all OTSGs/SGs including OTSGs and SGs that are only connected above a particular heat/power level.

8.5.2.4 Partial Steam Extraction

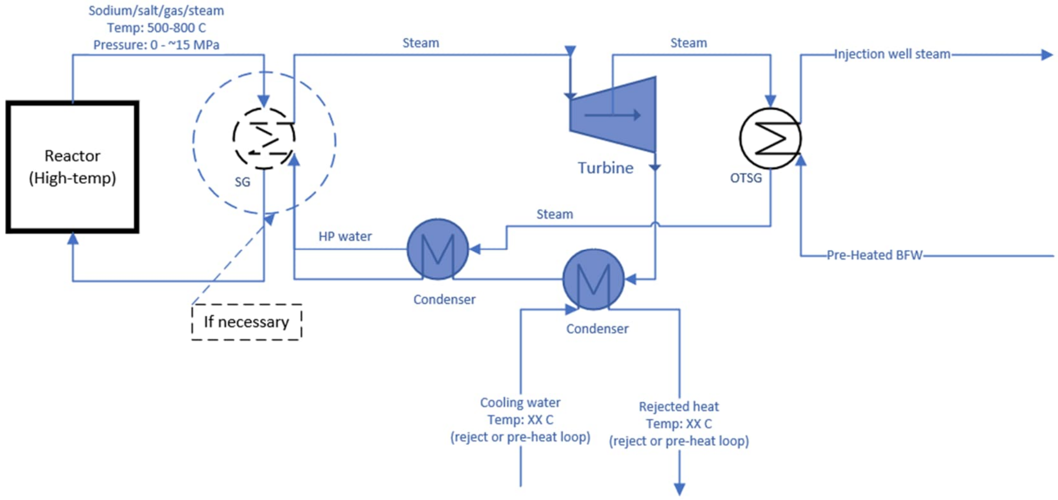


Figure 8-12: Coupled Co-Generation: Partial Steam Extraction

Partial steam extraction was investigated, and an example of a deployment configuration that was considered is shown in Figure 8-12. It has been deemed infeasible because steam is not able to condense through the OTSG and so must do so across a condenser. In the configuration, only a small share of reactor power can be delivered to the SAGD steam.

8.5.2.5 Supercritical CO_2

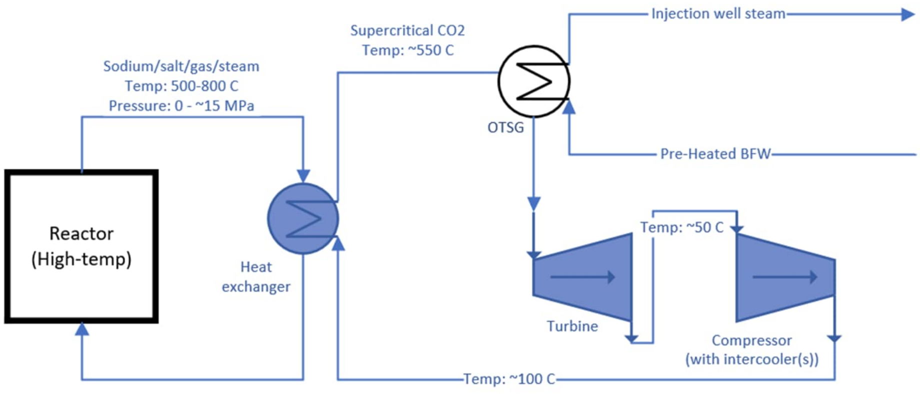


Figure 8-13: Coupled Co-Generation: Supercritical CO2[43]

Any configuration that has an intermediate loop condenser does not allow for a significant fraction of heat to be deposited to the SAGD steam. One way to avoid a condenser is to

[43] A supercritical CO2 deployment can be configured with a compressor or condenser + pump. A compressor is shown because it is the more common configuration in literature.

never bring the working fluid below saturation temperature and cause it to condense. A potential solution is to use a superheated gas or supercritical working fluid. The well-established technologies include supercritical CO2, air and helium. Supercritical CO2 is selected as the best fit among these options due to the slightly higher power cycle efficiencies and lower compressor power required; a potential configuration is shown in Figure 8-13.

Apart from the partial steam configuration, which is ruled out, the other co-generation deployment configurations have separate SAGD steam and electricity production loops. The loops may draw from a common steam header or salt tank yet are ultimately independent. The common loop has at least two notable advantages:

- Higher average hot fluid temperature through the OTSGs resulting in more effective heat transfer across the OTSGs.
- Reduced piping requirements: A continuous loop requires less length and fewer junctions resulting in lower costs and a reduced probability of pipe failures. This piping is to contain high temperature molten salt or high-pressure steam.

Yet, configurations with a common loop also have two primary disadvantages:

- Reduced efficiency: It would be preferable to operate the turbine at the high temperature portion of the loop where a significantly higher efficiency could be achieved. Although the average hot fluid temperature through the OTSGs would not be as high, the SAGD steam production is expected to still achieve nearly 100% thermal efficiency regardless. The high temperature requirements of the OTSG likely render such a setup infeasible.
- Elimination of the ability to transition between SAGD steam and power production: Since all of the heat transport fluid must pass through both the OTSGs and power cycle, only a limited variation in the ratio of SAGD steam and power production can be achieved. This would cause a significant reduction in reliability, likely requiring the use of backup natural gas OTSGs.

These two disadvantages likely outweigh the relatively minor benefits of a higher average temperature through the OTSGs and reduced piping requirements. As a result, this configuration is not suggested.

8.5.3 Co-Generation Discussion and Conclusion

Potential deployment scenarios where SMRs are used to provide both electricity and process heat for SAGD steam production (co-generation) have been presented in this section. The selection of a co-generation deployment is challenging since it should consider the number of SMRs assigned to generate electricity and process steam as well as the temperatures and composition of the heat transport fluids involved. Moreover, for a given set of conditions there are often multiple co-generation deployments that are feasible.

The reliability of SAGD steam production is an important consideration that can be enhanced substantially through the ability to transition between SAGD steam and power production. A decoupled deployment configuration does not allow for this ability to transition and should therefore be avoided in most scenarios. A coupled deployment becomes more challenging as the reactor temperature decreases, and so the decoupled deployment would likely be favourable if water-cooled reactors, such as IPWRs/PWRs are used.

Splitting heat between SAGD steam production and electricity generation in a coupled deployment can occur at either the primary heat transport loop or a combined intermediate loop. Heat can be extracted from the primary heat transport loop in either a parallel or series configuration; regardless of the configuration, this strategy has significant challenges and allows for only a limited ability to transition between SAGD steam and electricity production. A combined intermediate loop is therefore the preferred coupled deployment configuration. Several other configurations were explored, such as partial steam extraction and configurations involving a non-condensing gas, particularly supercritical CO_2. These deployments were found to have more issues and/or challenges and are therefore generally not suggested over the other, more straightforward, scenarios discussed.

8.6 Deployment Configuration of the Down Selected Reactor Design(s)

The technology and deployment configuration selection should be developed concurrently. Knowledge of the expected deployment configurations of the shortlisted reactors effects the scores given to several evaluation criteria.

A multiple of reactor power is unlikely to precisely meet the target SAGD steam demand and electrical generation and it is uneconomical to operate the reactor(s) below the rated power. If the deployment includes a target level of electricity production, the amount of electricity production can be adjusted such that the reactors can operate at full power, meet the steam requirements and not waste energy.

The development of the deployment configurations for the down selected designs should consider radiological protection, thermal energy storage, reliability, alternative co-generation (the use of back-pressure turbines, partial steam extraction, etc.). These issues are explored generally for all reactor designs throughout Section 8.

8.7 Electricity Production

In this section several electricity generation scenarios are explored for the generic SAGD facility case with a power demand of 18 MWe. The cases explored are intended to communicate the effect the level of gross electricity production has on make-up water and parasitic load as well as explore the costs of the electricity generation and consumption options. Scenarios, summarized in Table 8-6 are analyzed.

It is suggested that the reference deployment scenarios of the selected reactor design(s) be constructed to most closely align with scenario 1, where the minimum amount of nuclear energy is produced to meet both the SAGD steam requirements and maximum back door electricity demand (assumed to be 20 MWe). The estimates in the table are conservative, the reactor parasitic power draw (gross – net) is likely to be lower than the values provided. It is assumed that the number of reactors producing power is 1 in all scenarios.

Table 8-6: Electricity Production Scenarios

No.	Description	*Max. Load for Site Back-Door [MWe]*	Total Gross Power Output [MWe]	Min. Power for Grid Export [MWe]
1	Primary Net-Exporter: Minimum The SMRs produce the minimum amount of electricity required to continuously meet back-door demand	20	23	0
2	Primary Net-Exporter: 20 MWe The SMRs produce 20 MWe more than the minimum amount required to continuously meet back-door demand.	40	46	20
3	Primary Net-Exporter: 100 MWe The SMRs produce 100 MWe more than the minimum amount of required to continuously meet back-door demand.	100	115	80

The three scenarios are all cases where nuclear energy produces all power on site and the nuclear power generation continuously exceeds site power demand under normal circumstances. Excess site power is exported to the grid.

8.7.1 Make-up Water and Parasitic Load Requirements

The power cycle requires a means to discharge low-temperature heat from the condenser. Several options have been identified:

1. Once through: Water from a large body (river/lake) flows through the condenser absorbing heat from the working fluid. Approximately half of Nuclear Power Plants (NPPs) in North America, including all Canadian NPPs use this cooling method.
2. Evaporative cooling (cooling tower): This method uses the typical cooling tower that is often associated with NPPs. It makes up the other half of North American NPP cooling systems.
   - Power draw: 12.4 kWe per MWth discharge[44].
   - Corresponds to 1.0% of electrical power at 40% efficiency. Estimated water consumption: 1.9 m^3/MWh-e, 40% efficiency. Based on data from[45] [46].

[44] https://www.powermag.com/how-thermal-power-plants-can-save-80-of-their-water/. (The kWe/MWth discharge value is calculated assuming the source data is based on a 35% thermal efficiency)
[45]https://reader.elsevier.com/reader/sd/pii/B9780081005163000095?token=5408655D7DF864D2AF7BFEB653F6435DF137080A62B1BD44996C2F9208E65F64F00B4C4E9997966EEE2A2C4CFD8BAB84&originRegion=us-east-1&originCreation=20230427150438.
[46] https://www.powermag.com/how-thermal-power-plants-can-save-80-of-their-water/.

3. Dry cooling (or Air-Cooled-Condenser): Straightforward air-to-air heat exchanger.
   - Power draw: 1.0% of thermal power (slightly less than evaporative cooling[47]).
   - Power draw is a strong function of ambient air temperature[48]: "ambient air temperature also has a significant impact on dry cooling system performance and cost."
   - Water consumption: 0 m^3/MWh-th.
   - The primary disadvantage is the higher turbine outlet temperature/pressure and resultant efficiency loss on hot days rather than the power draw.
4. Adiabatic dry cooling: the process of reducing heat through a change in air pressure caused by volume expansion.
   - It is a dry cooling system with the incorporation of pre-cooling pads. Hot, dry inlet air is cooled as it evaporates water in the pre-cooling pad. The pre-cooled air can now more effectively absorb heat from the working fluid through the dry cooler.
   - The system operates as a dry cooler for most of the year. It only uses water for adiabatic cooling of the intake air when the ambient air temperature or cooling load is high.[49]
   - Power draw: Similar to a dry cooling system.
   - Water consumption: 0 m^3/MWh-th on most days, approaches that of evaporative cooling on the hottest days.

8.7.1.1 Discussion

Whether the site has a sufficiently large body of water available that is suitable for once-through cooling should be examined. Both evaporative and dry/adiabatic cooling should be explored, some points to consider in the selection of a cooling method include:

- Large NPPs can spread the cost of water acquisitions, licences, etc. for an evaporative-cooling system over a higher overall cost. These indirect costs are much lower for a dry/adiabatic cooling system.
- Dry cooling costs are much more sensitive to temperature. As a result, dry cooling is generally more suited to cold climates (the northern Alberta climate is on average colder than the location of any NPP in North America).
- The northern Alberta climate is very seasonal so the inclusion of pre-cooling pads for hot days can significantly reduce the size and therefore capital costs of the system.

[47] https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/workshop_oakland2005/pres_jmaulbetch.pdf.
[48] https://cedmcenter.org/wp-content/uploads/2017/10/Performance-and-cost-of-wet-and-dry-cooling-systems-for-pulverized-coal-power-plants-with-and-without-carbon-capture-and-storage.pdf.
[49] https://www.vistechcooling.co.uk/knowledge-centre/articles/faqs-adiabatic-coolers-vs-open-cooling-towers/.

- A 2018 National Energy Technology Laboratory study found that the capital costs for wet and dry cooling systems are 3.0 and 3.6% of the total capital cost of a pulverized coal power plant.[50] The cold climate of northern Alberta should reduce the relative difference further. Regardless, the capital cost is expected to be less of a determining factor in the selection of a cooling system than power draw or water consumption.

Adiabatic dry cooling, which includes the incorporation of pre-cooling pads, is likely preferable to dry cooling because the relatively low water consumption of the adiabatic pre-cooling pads are less of an issue than the higher capital costs and efficiency reduction on hot days of a dry cooled system.

8.8 Deployment Scenarios: Summary and Conclusions

Several different deployment scenarios have been developed in this section to demonstrate how SMR technologies may interface with an existing SAGD operation. A discussion of considerations common to all deployments has been presented including:

- The inclusion of at least three (3) barriers between radioactive material and SAGD process fluid.
- Approaches to achieve a high level of SAGD process steam reliability. While multiple approaches ultimately are feasible, a deployment utilizing SMR units that can be transitioned between electricity and SAGD steam production is suggested to provide flexibility and reliability of steam production and to eliminate the need to rely on natural gas or other fossil fuels for backup power.
- Thermal energy storage and controls to minimize impacts of potential process steam demand interruptions on the SMR unit. Depending on the type of intermediate loop and coupling between the SMR and the SAGD process steam, thermal energy controls can be provided either using a molten salt loop and storage tanks or a steam bypass and conditioning system. Depending on the duration of storage required for a given site, a specific trade-off study between the cost of increased thermal energy storage and benefit to the plant should be completed given the potential costs associated with molten salt storage tanks over longer durations.

Differences between reactor types were discussed along with related impacts on the design of the interfacing facility between the nuclear island and SAGD process steam. This includes the capability for non-water-cooled reactors (high-temperature reactors) to supply nuclear heat directly to the SAGD steam while water-cooled reactor configurations were found to require additional energy input by either a supplemental heat source or steam compression to meet the SAGD steam temperature and pressure requirements.

There are many potential co-generation configurations in a SAGD environment, and several are explored in Section 8.5. In a decoupled deployment, the heat produced to support SAGD steam generation is from separate, dedicated SMR modules. Separate modules are then

[50] https://www.osti.gov/servlets/purl/1529314.

used to meet the site electricity demand and any net export requirements. While this approach provides some flexibility in SMR unit selection, a coupled heat and power co-generation configuration is suggested because it supports a high reliability of SAGD steam production by allowing reactors to switch between electricity and SAGD steam production based on reactor availability and overall steam and power demand.

Although it could be beneficial to produce power to meet the site load, it is likely uneconomical to export to the grid. This is largely because the price of purchased power that utilities charge almost always substantially exceeds the wholesale price received for exported power. Unless a sufficiently large body of water is available for cooling, adiabatic dry cooling is likely the most appropriate power-cycle heat rejection mechanism.

9. SMR Technology Assessment and Down Selection

9.1 Assessment Framework

Given the rapid growth of the SMR industry over the last number of years, and the increasing diversity of technology offerings, assessing the potential suitability of the various SMR vendor offerings on the market can be difficult. Hatch's SMR screening and assessment methodology has evolved over the years through lessons learned and to reflect the development of the SMR market. Figure 9-1 provides a summary of this framework.

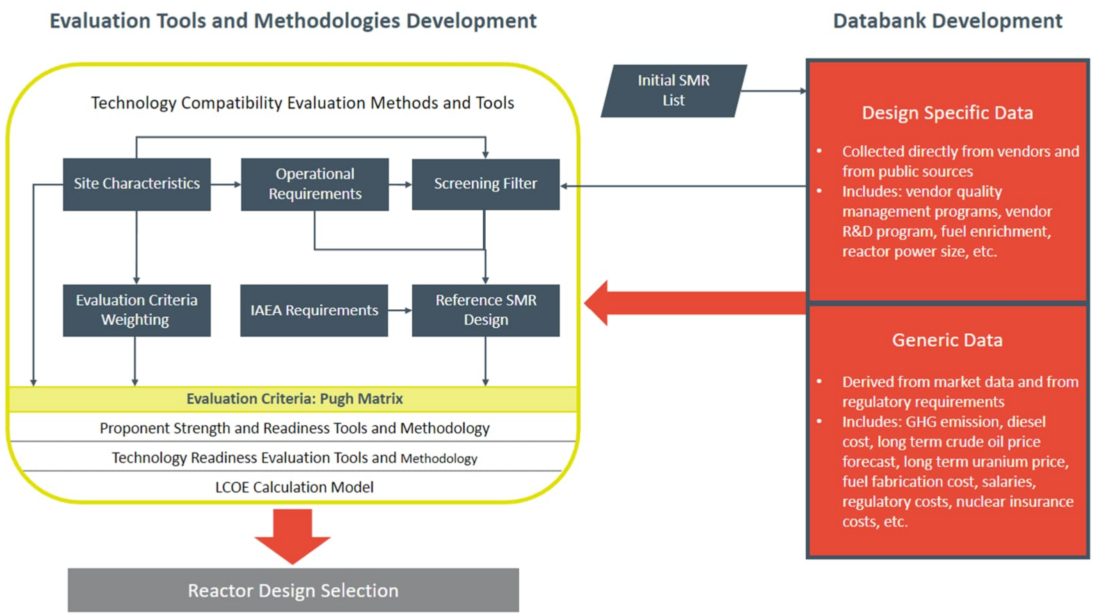


Figure 9-1: Evaluation Framework

As the SMR market is rapidly changing, the basis used for the technology assessment and evaluation in this report is likely to shift in the coming years. Although Hatch anticipates that its tools and methodology will remain valid in the future, it is suggested that the selection process is re-evaluated, and input data is updated when a significant development in the SMR industry occurs or a SAGD SMR deployment progresses to the next phase.

The first part of the methodology is to develop a shortlist of reactor designs that are compatible with the site and have a realistic chance of being selected through the evaluation. The evaluation itself consists of the following four assessments:

1. Technology Compatibility Assessment.
2. Technology Readiness Assessment.
3. Proponent Strength and Readiness Assessment.
4. Levelized Cost of Energy.

9.2 SMR Reactor List & Initial Screening

9.2.1 Development of Initial SMR List

The initial stage of Hatch's SMR evaluation methodology involves the generation of a broad listing of SMR vendor technologies. The purpose of the list is to serve as input to a screening filter to produce a short-list of technologies for further analysis.

The initial list of SMR technologies is built based on public information. Potential sources to draw upon include established nuclear information sources, media publications, and corporate websites including:

- The IAEA Advanced Reactors Information System (ARIS) database.[51]
- The list of vendors either engaged with the Vendor Design Review (VDR) program with the CNSC or who have submitted a licence application to the CNSC related to an SMR project.[52]
- Vendors engaged with either the U.S. Nuclear Regulatory Commission (NRC), the US Department of Defence (DOD), the US Department of Energy (DOE), or the UK Office of Nuclear Regulation (ONR) on either the development or licensing of an SMR.
- The Nuclear Energy Agency (OECD/NEA).[53]
- UxC Consulting Company SMR listing.[54]

9.2.2 Screening of Initial SMR List

The initial SMR list is screened to identify technologies that broadly satisfy the deployment conditions and to develop a screened SMR input list to the more detailed compatibility assessments. To screen the initial listing of SMRs the following criteria have been used:

- Country of Origin
- Module Size (Upper & Lower Bound)

[51] https://aris.iaea.org/.
[52] https://nuclearsafety.gc.ca/eng/reactors/power-plants/pre-licensing-vendor-design-review/?pedisable=true#:~:text=A%20Pre-Licensing%20Vendor%20Design,on%20a%20vendor%27s%20reactor%20technology.
[53] https://www.oecd-nea.org/jcms/pl_78743/the-nea-small-modular-reactor-dashboard?details=true.
[54] https://www.uxc.com/p/products/pdf/UxC-SMRA%202010-12%20TOC.pdf.

- Design Maturity and Corporate Activity
- Application
- Reactor Technology.

The following subsections provide the justification for the inclusion of these screening and filtering categories as well as how they will be applied.

9.2.2.1 Country of Origin

SMR designs should ideally be developed in countries that have friendly, productive relations with Canada. There should be minimal risk that a breakdown in geopolitical and/or trade relations impede the project.

9.2.2.2 SMR Module Size (Upper Bound)

AN SMR deployment for a SAGD facility should address backup generation or steam production when a unit is removed from service due to planned and unplanned outages. By deploying multiple SMR modules on a single site, the reliability of the steam supply increases and the use of backup generation or steam production decreases. While there are many alternatives that can be used to provide power or steam during SMR unit outages, an SMR deployment at site that allows for more than one unit is preferred.

9.2.2.3 SMR Module Size (Lower Bound)

SMRs use an economies of multiples strategy to offset efficiency losses from economies of scale. However, within the SMR landscape, economies of scale are anticipated to continue to broadly apply in that the deployment of a 75 MWe or 300 MWe module is anticipated to be cheaper than deployment of a 5 MWe module on a levelized cost basis. Furthermore, the deployment of fewer large reactors generally is anticipated to require less land area than a higher number of lower capacity units.

Small differences in the number of modules are not expected to significantly affect the cost or ability to deploy an SMR project. However, the deployment of dozens of reactor modules on an individual site may start to challenge available land and make integration with the industrial facility more challenging. While this is a site and project specific criteria, there is a preference to limit the total number of modules deployed in a specific deployment environment.

9.2.2.4 Corporate & Design Maturity

In reviewing the landscape of SMR vendors globally, many vendors are noted to be early in the engineering development lifecycle of their reactor technology. To allow for near-term deployment, preference is generally given to vendors that are actively engaged with regulators, utilities, end-users, delivery partners, and other stakeholder groups in the development and delivery of their SMR technology.

9.2.2.5 Application

Any SMR being developed solely for R&D purposes or as a technology demonstrator is excluded from further analysis. However, commercial versions derived from these demonstration reactors should be assessed for applicability to the deployment environment.

For the specific SAGD application investigated in this report, marine based SMR technologies have also been excluded from consideration as they do not align with the intended deployment environment considered for this study.

9.2.2.6 Reactor Technology

SMRs being deployed for SAGD applications involving steam production are required to provide sufficient separation between the radiological elements of the reactor (Nuclear Island) and the process fluid being used for oil extraction. Reactors that use the same working fluid as a coolant in the reactor core and to generate power through a turbine have a simplified system design for power generation when compared to competing technologies. However, this configuration presents challenges in process heat applications. This includes the lack of a heat exchanger where steam is produced outside of the primary loop.

In these styles of reactors, as the primary coolant from the core is sent directly through the turbine, the turbine itself and all other power block components must exist within the nuclear island. Generally, this arrangement will cause these components to also become activated (radioactive) over time. To provide appropriate separation between radioactive working fluids and process steam for injection, at least two layers of separation (the third layer is the fuel cladding) are required such that in the event of a tube leak or other event, no contamination can cross the boundary to the process steam supply. To provide sufficient separation between the reactor coolant and the process steam supply, the introduction of a heat exchanger and an intermediate heat transfer loop is considered a likely regulatory requirement. This intermediate heat transfer loop would then be coupled to the OTSG's or other Heat Exchangers used to generate process steam.

By introducing a heat exchanger into the reactor design, a significant deviation is introduced to the standard utility-power design of these reactors. As a result, consideration should be given to screening out reactor types where coolant directly drives a turbine. If it is acceptable for multiple types of SMRs to exist on the same site, these single-loop SMRs could be deployed to support the electrical demand of a SAGD facility while other SMRs are used for steam generation.

9.2.3 Development of SMR Shortlist

Based on the application of the initial screening criteria, a shortlist of SMRs is developed for further consideration. Applying the screening criteria to the listing of all SMR designs developed from sources described in Section 9.2.1 (for the specific deployment scenario for a Generic SAGD facility in Alberta) the following indicative list of SMR designs for further consideration has been generated. Note that the presence or omission of any specific SMR technology from this list does not necessarily indicate that it is not suitable for this deployment environment. A specific evaluation should be completed for any given site and/or deployment opportunity under consideration.

Table 9-1: Indicative List of SMR Designs for Further Consideration (In Alphabetical Order)

Reactor	Developer	Country of Origin	Capacity, MWe/MWth	Type
AP-300	Westinghouse-Toshiba	USA	300/900	PWR
ARC-100	Advanced Reactor Concepts	Canada	100/286	LMFR
Aurora	Oklo	USA	1.5/4	LFR
Bandi-60s	KEPCO	South Korea	60/200	PWR
BWRX-300	GE – Hitachi	USA	300/870	BWR
CANDU-300	CANDU Energy	Canada	300/960	PHWR
CAREM	Various	Argentina	25/100	IPWR
EM2	General Atomics	USA	265/500	HTGR
eVinci	Westinghouse	USA	3.5/12	Heat-pipe
IMSR	Terrestrial Energy	Canada	195/400	MSR
KP-FHR	Kairos Power	USA	140/320	MSR
LFR-small	Newcleo	Europe/UK	200/480	LFR
MMR	Ultra-Safe Nuclear Corporation	USA	10/30	HTGR
moltexFLEX	Moltex	Canada	16/40	MSR
Natrium	Terrapower	USA	200/480	LMFR
Nuward	EDF, etc.	France	170/540	MSR
PRISM	GE-Hitachi	USA	311/840	LMFR
SEALER-55	Leadcold	Canada	55/140	LFR
SMART	KEARI	IPWR	107/365	IPWR
SMR-160	Holtec	USA	160/525	PWR
SSR-W	Moltex	Canada	750-1250	SR
VOYGR	NuScale	IPWR	77/250	IPWR
Westinghouse LFR	Westinghouse	USA	450/950	LFR
Xe-100	X-Energy	USA	80/200	HTGR

9.3 Hatch SMR Technology Assessment Framework

Criteria used for the Hatch SMR Technology Assessment are discussed below. This is followed by a brief discussion of the challenges associated with comparing/combining the various assessments to make a reactor technology selection(s). This assessment process was applied to the reactor designs that passed the initial screening per Table 9-1.

9.3.1 Technology Compatibility Assessment

The technology compatibility assessment should be tailored to assess the technology compatibility of the subject SMR for the deployment scenario at the selected site. This is completed with the use of a Pugh matrix evaluation. Site requirements are to be further combined with applicable IAEA user considerations[55] to develop the technology requirements and the reference SMR's design features.

In addition to the reference SMR's design features, criteria weighting is necessary for a Pugh Matrix evaluation. A weighting scale should be developed by assigning importance scores to each evaluation criteria and their categories, and subsequently normalizing the scores. This process eliminates evaluation bias that comes from having a different number of evaluation criteria under each category.

A detailed walk through of the process followed of the Technology Compatibility Assessment is provided in Section 9.4 of this report.

9.3.2 Technology Readiness Assessment

The TRL can be interpreted as one of two measures.

1. The readiness of the specific design: i.e., the level of progress of the design. A design at the conceptual stage would score low while a complete detailed design would score highly.
2. The readiness of the technology generally: i.e., the level of development of the technology (PWR, SFR, HTGR, etc.). It is largely a function of the amount of past and present operating experience.

A reactor design can score dramatically differently on either metric, and it is not immediately clear which measure is more useful. A very early-stage PWR is based on a foundation of well-established technology that operators, engineers and regulators are familiar with. It would therefore score very highly on metric #2. Yet if little design work, beyond establishing the concept, had been completed, it would score very poorly on metric #1. Conversely, a well-developed design that has undertaken several lab demonstrations of key systems but is based on entirely new, largely unproven systems and materials, will score high on metric #1 but poorly on metric #2. It is unclear which design carries more risks and which has a quicker overall deployment time, but the competing drawbacks suggest that the two should be scored similarly. An average of the two measures should result in a similar score and be reflective of the relative readiness of a design for deployment. Technologies are scored on a scale

[55] INTERNATIONAL ATOMIC ENERGY AGENCY, Common User Considerations (CUC) by Developing Countries for Future Nuclear Energy Systems: Report of Stage 1, IAEA Nuclear Energy Series No. NP-T-2.1, IAEA, Vienna (2009).

ranging from 1 to 9., A score of 1 is assigned to technologies where only basic principles have been observed and reported, while a score of 9 is assigned when the actual technology has been proven through successful deployment in an operational environment. A detailed description of potential TRL scores is provided in Appendix G. Section 9.5 of this report provides an overview of the TRL assessment undertaken for this study.

9.3.3 Proponent Strength and Readiness Assessment

For the Proponent Strength and Readiness assessment, the proponent is defined to include three different entities who together are significantly responsible for the success of a project. The strength of each of these proponent entities is assessed independently and to different criteria. The criteria for assessment of each proponent type are listed in Table 9-2. A detailed description of the proponent Strength and Readiness Assessment completed for this study is provided in Section 9.6 of this report.

Table 9-2: Summary of Proponents Strength and Readiness Level Criteria

Licence Applicant	Operating Experience
	Reputation
	Financial Strength
	Familiarity with SMR Technology
	Proximity to Site/Relevance to Jurisdiction
Technology Vendor	Technology Development Status
	Regulatory Approval Status
	Corporate Structure
	Financial Strength
	Quality Assurance
	Pedigree
EPC/EPCM Partner(s)	Corporate Structure and Financial Strength
	Level of Engagement
	Delivery Capability
	Resource Pool
	Track Record
	Scope of EPC/EPCM Capabilities

9.3.4 LCOE Calculation

The LCOE calculation undertaken in this study is strictly for the purpose of reactor selection. The methodology and level of detail are selected to serve this goal. All costs, and especially capital costs are highly uncertain for the majority of SMR deployment scenarios. Accordingly, the LCOE estimation for this study is conducted in largely a technology, configuration, and location agnostic manner. As such, costs are primarily a function of reactor capacity (economies of scale) and number of units (co-siting).

9.3.5 Multicriteria Decision Analysis Framework

Decision-making is a complex issue, strongly characterized by conflicting aims, that often results in a situation where there are trade-offs. Multiple criteria or multicriteria decision analysis (MCDA) is the collective name of approaches and methodologies that support decision making by considering multiple criteria in an explicit and transparent way.

MCDA in this application, allows participants to cumulatively rank the SMRs under consideration by undertaking a comprehensive assessment in a structured manner. It is an inclusive assessment rather than individual assessment streams. MCDA brings together the PSRL, TRL and LCOE calculation assessments that were previously conducted.

There is fundamentally no straightforward way to quantitatively compare all components, Pugh matrix results, PSRL, TRL and LCOE. Each are measured on different scales. The scales are not necessarily linear and the relative differences between reactors can vary considerably. Establishing a weighting to each component is inherently dependent on how each is scaled and thus the weighting would not accurately reflect the intended contribution of each component. Although there are many MCDA frameworks (Analytical Hierarchy Process, MACBETH, Discrete choice experiments, etc.) that are meant to reduce bias, some bias or professional judgement is inherent to this selection, regardless of the MCDA used. In Hatch's opinion, any rigorously structured MCDA decision making approach is not recommended because the risk, caused by the additional complexity of overlooking the inherent bias, outweighs the marginal gains in the potential for initial bias reduction from a structured approach.

Selection of Final Technologies based on MCDA is detailed in Section 9.8 of this report.

9.4 Technology Compatibility Assessment

Hatch's proprietary variation of a Pugh matrix, also known as a decision-matrix, was used to compare SMR technologies. A Pugh matrix is a tool used to compare options by assigning rankings and importance weightings to specific criteria based on available data. Some criteria are quantitative by nature while others are qualitative and must be assigned rankings based on professional and expert judgement.

Based on the project and site characteristics, a list of idealized SMR characteristics should be established based on CNSC and IAEA technical documentation and regulatory requirements review. To compare multiple SMR technologies, a baseline "reference SMR" should be developed prior to ranking. Criteria identified in the development of the reference SMR are the criteria all SMR's shall be compared against.

9.4.1 *Reference SMR and Criteria Development*

A set of specific criteria for a hypothetical reference SMR should be developed to provide a baseline for the comparative analysis. The rationale in developing a hypothetical reference reactor is to identify all important desired features relevant to this SMR deployment. From the desired features, baseline criteria can be assigned to which each considered SMR can be compared against. Hatch's proprietary baseline development methodology that should be used to develop the desired features baseline criteria is shown in Figure 9-2.

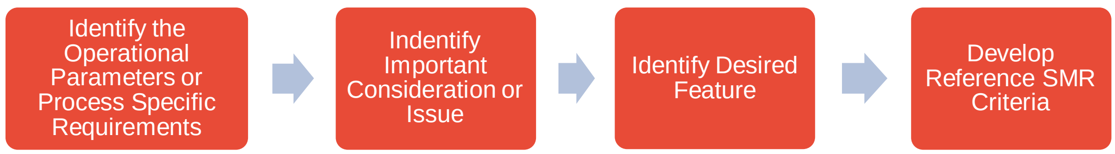


Figure 9-2: Reference SMR Development Methodology

To identify important considerations and issues relating to SMR deployment, the following should be considered:

- Regional and site-specific characteristics.
- IAEA Publication No. NP-T-2.1, Common User Considerations (CUC) by Developing Countries for Future Nuclear Energy Systems: Report of Stage 1 – This publication describes common characteristics of desired features requested by potential users of small nuclear power plants in remote locations. It covers general technical and economic characteristics of desired nuclear power plants and associated services and supports.
- CNSC: CNSC regulatory documents were reviewed to understand how the regulatory guidance relates to the reactor technology and process configuration. Key documents include:
  - Small Modular Reactors: Regulatory Strategy, Approaches and Challenges.[56]
  - REGDOC-1.1.1, Site Evaluation and Site Preparation for New Reactor Facilities.[57]
  - REGDOC-1.1.2, Licence Application Guide: Licence to Construct a Reactor Facility, Version 2.[58]
  - REGDOC-1.1.3, Licence Application Guide: Licence to Operate a Nuclear Power Plant, Version 1.2.[59]

By considering both site specific characteristics and the CUCs, both application specific and non-application specific desired features can be developed. Quantitative and/or qualitative baseline criteria should be assigned to each desired feature to establish a baseline for the

[56] http://nuclearsafety.gc.ca/eng/acts-and-regulations/consultation/comment/d-16-04/index.cfm#sec2.
[57] http://www.nuclearsafety.gc.ca/eng/acts-and-regulations/regulatory-documents/published/html/regdoc-1-1-1/index.cfm#sec3-3.
[58] http://www.nuclearsafety.gc.ca/eng/acts-and-regulations/regulatory-documents/history/regdoc1-1-2.cfm.
[59] http://www.nuclearsafety.gc.ca/eng/acts-and-regulations/regulatory-documents/history/regdoc1-1-3.cfm.

comparison of SMR technologies under consideration. The list of desired features and baseline criteria relevant to a SAGD deployment are identified in Table 9-3, discussed below and are to be used for the Pugh matrix analysis. The following section, *Weighting Factors* (Section 9.4.2), outlines how importance was applied to each of the categories and criteria for SMR deployment.

Initially, a long list of evaluation criteria should be developed, and should include as many considerations as possible. This initial list of criteria should then be filtered to remove from the evaluation those criteria that are:

1. Non-discriminatory: All reactor designs are expected to be scored the same on the criteria and/or insufficient information is available to assign different scores.
2. Duplicates: The criterion captures a metric that is already covered by one of the other criteria, TRL, PSRL or LCOE.

The suggested criteria are grouped into six categories, each of the categories and criteria are discussed in the subsequent sections.

9.4.1.1 SAGD Integration and Performance

This category includes aspects that affect how the reactor integrates with SAGD steam production. It includes considerations such as temperatures, back-up heat source, protection from radioactive contaminants, etc.:

- **Temperature and pressure:** Certain SMRs cannot fully meet the SAGD temperature and pressure requirements without using additional energy sources (e.g., natural gas).
- **Nuclear backup energy:** Having a high uptime of SAGD production (i.e., reliability) is important. Nuclear reactors without any backup power system would not have sufficient reliability, since they need to be shutdown periodically for fueling and/or maintenance and there may be a significant number of unplanned shutdowns. In the event of a loss of reactor power, SAGD steam production can be replaced by nuclear energy (either diverted from electricity production, from oversizing/redundancy or thermal storage) or another heat source – very likely natural gas. This criterion is concerned with the question of how important it is that the backup energy source is nuclear.
- **Capacity factor (CF):** CF is the fraction of time that SAGD steam is being produced from nuclear power. It is equal to the actual nuclear SAGD steam production divided by the maximum nuclear SAGD steam production; For example, if steam production is operating at 80% of the maximum, 100% of the time' it would result in an 80% CF.
- **Outage time**: When a reactor trips, it may require some time before the reactor can restart due to Xenon poisoning. As well, most reactors must be shut down to refuel. Outage time is a measure of the importance of being able to restart the reactor quickly. If it is important to minimize the duration per outage, not necessarily the total outage time, this criterion should be assigned a high weighting. If there will be nuclear backup power in place or if it is not an issue, economic, environmental, or otherwise, to use natural gas

to temporarily replace the lost production capacity, then outage time is likely not concerning.

- **Standard design:** This criteria deals with how important it is that the reactor can be installed in its standard design configuration, without extensive modification. This criterion is added because the addition of an intermediate loop can substantially change the standard design. The criterion is a measure of the benefit of having a simple, easy to design/construct tie-in with SAGD production.

9.4.1.2 Other Technical Performance

This category considers how well the SMR(s) can perform functions other than strictly producing SAGD steam. It is composed of criteria that are site-specific and are similar to the criteria found in the *SAGD Integration and Performance* and *Site Compatibility* categories. Since the criteria relate to a common issue of energy generation, they are placed together in this separate category.

- **Power generation:** This is a measure of the importance of being able to generate all electricity requirements for the site.
  - If achieving a carbon-free (or carbon-neutral) operation is very important, the site should not import power and this criterion should have a high weighting.
- **Load following capability:** Measure of the weighting that should be assigned to the ability to match fluctuations in the site load.
  - If the site load can be met with grid interconnection or natural gas co-generation units and there is little/no issue (emission, economic, etc.) in doing so, this criterion should be given a low weighting.
- **Heat Production Demand Matching:** Measure of the importance that should be assigned to how well the reactor thermal capacity matches SAGD demand.

9.4.1.3 Site Compatibility

The *Site Compatibility* category pertains to the effort that is required to co-locate an SMR at an existing facility. It includes criteria such as footprint, exclusion zone, modularity, deployment flexibility, etc.

- **Exclusion zone:** nuclear power plants have a certain exclusion zone around the plant. The exclusion zone is under control of the licensee and other operations should not/cannot take place in this area. This criterion is a measure of how important is it that a plant be located close to the facility and have a small exclusion zone.
  - A low weighting should be assigned if there is plenty of space without other SAGD operations present and there is no meaningful expected loss of steam quality from the nuclear island to the steam header.

- **Plant asset life:** A measure of the importance that the nuclear plant asset life matches or exceeds the remaining SAGD site's operational lifetime.
  - For reference, the short-listed reactor designs have asset lives of approximately 30 to 80 years.
  - If one or more of the following apply, then this criterion should have a relatively low weighting:
    - The internal-rate-of-return is high and/or the investment time horizon is short.
    - Site will not be in operation for longer than the nuclear plant lifetime – this is expected to be the case for many of the reactor designs.
- **Footprint:** It is expected that the reactor(s) and plant tie-in footprint would be on the order of 300 m · 300 m (90,000 m^2). This is a measure of how important it is for the footprint to be minimized.
- **Deployment flexibility:** is a measure of the value of the reduction in economic risk (minimization of sunk cost by constructing reactors sequentially) and allowance for flexible future expansion that is due to the number of reactor units.
- **Modularity:** is a measure of the degree to which the SMR can be constructed off-site. The more systems that are contained within the reactor vessel unit and the smaller the reactor vessel, in general, the greater the share of construction that can be conducted off-site and the easier it is to transport the modular components. A modular reactor should be composed of components that can be transported by road or rail without additional infrastructure.

9.4.1.4 Schedule

The *schedule* category consists of criteria related to the deployment schedule (including, licensing and construction time). It is largely measure of the importance that SMRs can be installed at the site quickly.

- **Construction time:** A weighting of the importance of minimizing the on-site construction time.
- **Deployment time:** A weighting of the importance of minimizing the time until a reactor is deployed (in operation, producing heat for SAGD operations).
  - Deployment time = the time until reactor construction can begin (technology and design development as well as licensing) + construction time.
- **Licensing certainty:** Confidence in the duration and outcome of the licensing process. The weighting assigned to this criterion is a measure of the importance of avoiding the risk of licensing causing delays – either by the process taking longer than expected or having to re-submit due to the application(s) being rejected.

- **Vendor Design Review:** A measure of existing pre-licensing activities - ideally in Canada or the USA. This is a not a measure of site licensing activities because very few reactor designs have made site-specific licensing progress in Canada.

9.4.1.5 *Operations*

The *Operations* category consists of criteria related to operation (number of staff, fueling frequency, availability of spare parts, etc.).

- **Number of staff:** The reactor should be designed to use the fewest number of operators possible. This criterion is a measure of the importance of minimizing the number of operators. Qualified staff in this semi-remote location may be a significant operating expense. For reference, staffing costs are ~10% of LCOE in typical large nuclear power plants. Having a large complement of staff in the area may provide advantages in the future development of the nuclear industry in the area.
- **Maintenance and refueling frequency:** a measure of the importance of having a low refueling frequency. All else being equal, a high frequency will increase the amount of time the reactor is off-line and thereby reduce the capacity factor (CF). The capacity factor is however a separate issue. The frequency is concerned with the labour costs, contamination risks, proliferation risks, and challenges associated with refueling.
- **Existing OPEX:** Certain reactor technologies have more operating experience from other similar designs, while novel technologies do not have much past operating data. This is a measure of how important is it that OPEX is readily available. A lack of OPEX means that there are fewer quality assurance and quality control procedures, training programs, etc. available. The internal development of the procedures/ programs/ institutional knowledge may have advantages in the future development of the nuclear industry.
- **Availability of spare parts:** Reactor designs that have been constructed multiple times (or are under construction in multiple places) with components common to other industries, are expected to have more spare parts available and custom parts can be produced on a shorter timeline.

9.4.1.6 *Environment*

The *Environment* category is composed of criteria related to nuclear waste, cooling, and effluent discharge.

- **Thermal efficiency:** In power generation, SMRs with higher thermal efficiency consume less fuel (although this is only a small savings) and reject less heat (~60% - 70% of the reactor heat will be rejected to the environment), leading to a smaller heat sink requirement. Evaporative cooling (cooling towers) requires make up water and dry cooling results in higher capital costs and can reduce power cycle efficiency on hot days. The assigned weighting should reflect costs (environmental, economic, or otherwise) to reject heat from the power cycle.

- **Production of High-Level Waste (i.e., spent fuel):** Reactors do not produce an equal amount of spent fuel waste and there is a cost to managing and disposing of waste. As a result, this criterion is created to capture the cost difference.

9.4.1.7 *Description of Reference (Ideal) Reactor*

The final components to the criteria development are to come up with the desired features and baseline criteria for the hypothetical reference reactor. These ideal features are listed for each criterion in Table 9-3. The desired features are a description of what fully meeting the relevant criteria means and the baseline criteria is the quantitative value associated with fully meeting the criteria. On many occasions, the criterion is not explicitly quantifiable and so the desired feature description is all that is necessary.

Table 9-3: SMR Considerations, Desired Features, and Baseline Criteria

Category	Criteria	Desired Feature	Baseline Criteria[60]
SAGD Integration/ Performance	Temperature and pressure	Able to fully meet the SAGD temperature and pressure requirements without using additional energy sources (e.g., natural gas).	Same as desired feature
	Nuclear backup power	The source of backup power is also nuclear (as opposite to N.G. or others)	Same as desired feature
	Capacity factor	High-capacity factor	95%
	Outage time	Able to override Xenon poisoning and restart the reactor within approximately 5 hours? (As opposed to ~2 days without a Xenon override)	Refueling period in excess of 5 years and there is potential for Xe-transients
	Standard design	The reactor can be installed in its standard design configuration without an added intermediate loop or other extensive modification.	Same as desired feature
Other Technical Performance	Power generation	Able to generate electricity to cover all of the site's own consumption	Same as desired feature
	Load following capability	Able to match the site electrical load exactly and continuously with (a) SMR(s)	Same as desired feature
	Heat production and demand matching	Able to meet the heat capacity of SAGD steam production	A multiple of reactor capacity has a 30 MWth difference from the SAGD steam demand

[60] The Desired Features are generally qualitative statements and so the Baseline Criteria cannot be selected through rigorous literature review or calculations. They are therefore selected largely on the basis of professional judgment. Moreover, they should be considered mutable and subject to site specific considerations.

Category	Criteria	Desired Feature	Baseline Criteria[60]
Site Compatibility	Exclusion zone	The exclusion zone is small enough to allow the SMR to be located close to the facility	400 m from the plant boundary
	Plant asset life	The nuclear plant asset life matches or exceeds the remaining SAGD operation lifetime	60 years
	Footprint	The reactor footprint is comparatively small. The area used very minimally disrupts operations or future expansion.	Approximately 300 m X 300 m (90,000 m^2)
	Deployment flexibility	The number of reactors should significantly reduce economic risk (minimize sunk cost by constructing reactors sequentially) and allow for flexible future expansion.	4 units
	Modularity	The reactor vessel is one modular unit, constructed off-site that is able to be transported without additional infrastructure	Same as desired feature
Schedule	Construction time	The expected construction is short compared to competing SMRs; first concrete to operation of 3 years.	3 years
	Deployment time	The reactor can be deployed comparatively quickly, by the early 2030's.	Early 2030s
	Licensing certainty	Able to have confidence that the licensing process will go as planned. Minimal risk of licensing causing delays.	Low probability of rejection or significant delays
	Vendor design review	To have completed pre-licensing activities in Canada or equivalent in the USA	Same as desired feature
Operation	Number of staff	Requires only a small number of on-site operators and other staff	Fewest on-site operators as possible
	Maintenance and refueling frequency	The reactor refueling frequency (a refueled can operating for periods of time without to need to refuel is preferable)	Refueling cycle longer than 5 years
	Existing OPEX	OPEX is readily available	Reactors of the same technology are in operation in countries that have friendly relations with Canada

Category	Criteria	Desired Feature	Baseline Criteria[60]
	Availability of spare parts	The reactor has been constructed and/or components are common to other industries so spare parts are available and custom parts can be produced on a shorter timeline.	Reactors of the same model have been constructed or are under construction in countries that have friendly relations with Canada
Environment	Thermal efficiency	Has a higher thermal efficiency and so it consumes less fuel and reject less heat, leading to a smaller heat sink requirement	Thermal efficiency = 40%
	Production of High-Level Waste	The amount of spent fuel (High-Level Waste) produced is low compared to competing SMR designs.	~0.03 kg/MWh-th

9.4.2 *Weighting Factors*

The next step is to select weighting factors for each of the criteria. Ideally, the weighting factors are selected by multiple people who understand the evaluation criteria and therefore the implication of each weighting assignment. Because the weighting selection is an inherently imprecise activity, only four weighting options, shown in Table 9-4, are used. The additional complexity and risk of confusion and/or inconsistency is deemed more detrimental than the extra precision associated with more weighting options. As more information becomes available or priorities shift, the weightings may be altered in future analysis.

Weightings are to be provided for both the categories and the individual criteria. First, the weightings for each category are summed together. The category weights are then normalized (multiplied by a common factor that results in a total weighting of 1). After that, for each category, the weightings of the criteria in the category are summed together and normalized. Lastly, the category and criteria normalizations are multiplied to arrive at a final double-normalized value for each criterion. The double-normalized values represent the share of the total weighting that is assigned to each criterion.

Table 9-4: Weighting Options

Scoring Legend	Weighting
Very Important	3
Important	2
Somewhat Important	1
Not Important	0

9.4.3 Scoring

Scoring the SMRs should draw upon responses to vendor questionnaires if available but will largely have to be based on data from public sources. Some degree of expert judgment will have to be employed in the scoring of several criteria. Scores should be assigned based on the scoring legend presented in Table 9-5. For each criterion a scoring table should be developed to ensure consistent scoring of each reactor. The scoring tables are similar to those used to assign TRL and PSRL scores.

Table 9-5: Pugh Matrix Scoring Legend

Scoring Legend	Score
Exceeds the desired criteria	2
Meets the desired criteria	1
Not applicable / nearly meets the desired criteria	0
Only marginally meets the desired criteria	-1
Completely fails to meet the desired criteria	-2

9.4.4 Technology Compatibility Assessment Results: Pugh Matrix

The Pugh matrix, also known as a decision matrix, is where a total weighted score is applied to each reactor. The scores of each criterion are to be multiplied by each criteria weight and all the weighted scores added up to arrived at the total score for each reactor. Since the sum total of all weights is equal to 1, the reference reactor will receive a score of 1 and the maximum and minimum score each real reactor can achieve is 2 and -2 respectively.

9.5 Technology Readiness Level (TRL) Assessment of the SMR Shortlist

The Technology Readiness Level (TRL) is a metric that aims to measure the maturity of a technology while it is under development, prior to deployment. The TRL Evaluation Tools and Methodology were adapted from the U.S. DOE's TRL methodology [61], which itself was an adaption of NASA's TRL methodology with modification for nuclear technology evaluation. The assessment focuses specifically on how far an SMR vendor's technology development has proceeded by examining program concepts, technology requirements, and demonstrated technological capabilities. The assessment is designed to indicate the gap between a mature SMR technology and the analyzed SMR designs.

The technology readiness table, as detailed in Section 9.5, is then used to identify the maturity level of a given technology. The scale ranges from 1 to 9 with 9 being the most mature technology.

The Technology Readiness Level (TRL) framework can be applied to both components and systems of the technology in general (to be referred to as technology generally) or to the development of the specific SMR vendor design (referred to as design-specific). Both measures are highly relevant. The development of the systems, materials, analysis tools, etc.

[61] https://www.directives.doe.gov/directives-documents/400-series/0413.3-EGuide-04a/@@images/file.

for similar designs in the past is immensely beneficial to the readiness for deployment of the design. On the other hand, the TRL of the SMR itself is largely driven by how it has been developed, demonstrated, and piloted as an integrated whole vs. as a sum of its parts – thus the design-specific TRL component is very important as well.

In viewing the TRL evaluation framework, it should be noted that the TRL does not reflect on the quality of the technology implementation in the design. While ultimately TRL 9 technologies are commercially proven to be viable, lower TRL technologies may have latent issues that may prevent full commercialization that are not proven until more widespread deployment.

The Technology Generally score is made up of the following sub-components The scores should reflect the technology classification (SCFR, PWR, etc.) rather than the specific design.

- Safety systems
- Reactor physics
- Thermal hydraulics
- Materials
- Analysis Codes & Validation
- Fuel
- Control systems.

The total score should be the average of the Technology Generally and the Design Specifically scores, both are to be measured on the 1 to 9 scale. The overall TRL score is to be used in subsequent analysis to make the technology selection.

The *Technology Generally* scores in most cases, should be considerably higher than the *Design Specific* scores. The *Technology Generally* scores incorporate the experience of past projects. Further, a *Design Specific* score cannot substantially exceed a *Technology Generally* score because some level of technology development is required to progress in design.

9.6 Proponent Strength and Readiness Level (PSRL) Assessment of the SMR Shortlist

In the development of a nuclear power project, there are several roles designated by the CNSC that are carried out by different parts of the deployment organization. From the CNSC's guidance for new reactor facilities [62], the following definitions are presented:

- **Proponent:** the person, body, federal authority, or government that proposes the carrying out of a designated project. The proponent is responsible for the preparation of technical studies and findings for the conduct of an impact assessment or environmental review.

[62] http://nuclearsafety.gc.ca/eng/resources/frequently-asked-questions/new-reactor-facilities.cfm#Q10

- **Vendor:** The supplier of a reactor technology.
- **Applicant:** An organization or person that has applied to the CNSC for a licence or certificate. For example, an applicant for a licence to construct a nuclear facility has the overall responsibility for controlling and coordinating authority for overseeing the safe and satisfactory completion of all design, procurement, manufacturing, construction, and commissioning work.
- **Licensee:** A person who is licensed to carry on an activity described in paragraph 26(e) of the *Nuclear Safety and Control Act*.

In the Proponent Strength and Readiness assessment within this framework, the proponent definition includes three different entities who together are significantly responsible for the success of a project. These include:

1. The Applicant (which may also be the nuclear operator or Licensee).
2. The Vendor.
3. EPC & EPCM partners and other strategic partnerships involved in the project.

By considering each of these organizations under the umbrella of an SMR project proponent, a well-rounded view of the readiness and strength of the major parties involved in each proponent/vendor consortium can be obtained. Each of the entities within the proponent framework is ranked on different areas based on their relevance to the roles in the licensing, deployment, construction, and operation of an SMR project. A description of the Proponent Strength and Readiness Level criteria is provided in Section 9.3.3.

The PSRL Evaluation Tools and methodology were previously developed by Hatch through an adaption of NASA's technology readiness level (TRL) assessment methodology[63] , and customized to address the SMR industry. In addition, Hatch has identified the critical vendor elements for readiness evaluation. The assessment is designed to indicate the gap between a theoretical vendor who could successfully deploy an SMR technology in Canada and the SMR vendors under evaluation in this study. See Appendix H.

The average of the component criteria is used to assign a score to the Licensee, Technology Vendor, and EPC/EPCM partners, similar to how TRL scores are developed.

The overall PSRL score is a combination of the three components and the components should not necessarily be weighted equally. Consideration should be given to assigning the EPC/EPCM partners a lower weight because a poor EPC/EPCM score can be rectified more quickly and easily than the other two entities and is therefore less of a potential bottleneck/ impediment to development.

[63] https://www.directives.doe.gov/directives-documents/400-series/0413.3-EGuide-04a/@@images/file.

9.7 Levelized Cost of Energy

The precision and accuracy of capital cost estimates are very limited and in nuclear reactor builds, capital costs make up the majority of the LCOE. The lack of recent reactor builds, and variety of reactor designs necessitates the use of extensive extrapolations. A list of simplifying assumptions is provided in Table 9-6. It is recognized that many of the assumptions are important considerations that should receive attention prior to any reactor build, however, the impacts to the cost estimates are expected to be small relative to the high uncertainties and cost differences. Therefore, the use of simplifying assumptions is expected to have little impact on the reactor selection.

Table 9-6: LCOE Estimate Assumptions

Assumptions Made	Justification
Model is pre-tax.	Applies equally to each design. Has a relatively small effect.
No federal or provincial government funding, carbon credits, technology developer incentives, or other potential incentives are considered.	Applies equally (or nearly so) to each design.
All costs are presented in 2023 CAD.	Relevance and consistency.
LCOE assumptions: Construction time of 4 years with costs distributed equally throughout. 10% discount rate 60-year economic lifetime.	Discount rate of 10%: common rate used in the evaluation of potential corporate investments. A SAGD operation is expected to operate for multiple decades into the future, the reactors can be converted to generate power and all reactor designs generally have a lifetime of 60 years or longer.
Balance of plant costs are ignored.	Relatively small proportion of total costs. SAGD tie-in costs are difficult to estimate and are expected to be similar to power generation.
Reactor designs are FOAK.	Candidate reactors designs are likely to have not yet been constructed. Some designs are well developed, and construction is planned, however only a very small number are likely be constructed by the time of a SAGD deployment.

9.7.1 Cost Estimation Structure

Costs are broadly divided into capital and operating costs. Some reactor concepts employ core-swapping (or core-replacement) schemes. It is difficult to categorize the costs associated with core-replacement as either capital or operating. The suggested method to analyze the cost of core replacements is to spread the cost equally over the plant lifetime and thus treat core replacements as an operating cost, similar to refueling. The core replacement should be financed by continuous contributions to a core replacement fund. Reactor designs with the core replacement should be assigned a plant economic lifetime of 60 years for the LCOE calculations.

Key cost components are listed below. Whether each component is incorporated into the estimation is discussed.

1. **Capital costs:** includes costs incurred prior to operation. Three major components have been identified:

   i) Construction: Included in LCOE analysis.

   ii) Site specific licensing: Site licensing is a significant, relevant cost and so should be accounted for in the cost estimates. Many estimates of the total cost do not specify the site licensing costs (licence to prepare site, construct and operate), but it should be included in the estimate. Therefore, care should be taken to determine whether each cost estimate includes site licensing costs. If it does not, an additional $65 million (CAD, 2023) ought to be added.[64]

   iii) Design and technology development: Not included in LCOE analysis. The development of the design and the verification/validation of the technology is a high cost. This cost is expected to ultimately be distributed across the units deployed. However, development costs and the number of units over which these costs are to be distributed cannot be known. Moreover, design and technology development costs are essentially captured by the PSRL and TRL.

   All reactor designs at the time of construction are expected to be FOAK or nearly so, therefore FOAK should be assumed for all cost estimates. The cost estimates are concerned only with the cost of site-specific construction and operation of these FOAK reactors. Design and technology development, though necessary to complete prior to construction, is not site-specific and therefore should not be included in the capital cost. Site-specific design and licensing costs ought to be included in the capital cost.

[64] Estimated site-specific regulatory cost is based on: Review of VDR phase 1 & 2 respectively is 4000 & 9000 hr at $275/hr*, estimate of regulator fees is $60 M USD 2022** and ratio of 1:3.5, regulatory fees: internal support costs.
* https://nuclearsafety.gc.ca/eng/acts-and-regulations/regulatory-documents/published/html/gd385/index.cfm.
**https://world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power.aspx#:~:
text=Regulator%20fees%20are%20typically%20c,accruing%20during%20the%20construction%20period.

2. **Operating costs:** All costs incurred during regular operation, maintenance and refueling. All items listed should be included.

    i) Staffing: On-site staff are expected to be required to perform a variety of tasks to enable the SMR deployment including, operation/control, refueling, administration/support, maintenance, engineering, safety, and site services. There are likely meaningful differences between reactor designs, but due to a lack of complete designs and OPEX, the staff complement is estimated in a technology independent fashion. The number of staff required per MWth is calculated as a function of reactor capacity and the expected number of units.

    ii) Consumable operating materials (replacement parts, safety equipment, etc.): The difference in the cost between reactor designs is difficult to determine using a 'bottom-up' approach. Instead, an operating cost equal to 0.5% of the overnight capital cost is to be added to the total operating cost, the same strategy was employed in a 2014 Hatch study for the Ontario Ministry of Energy.[65] Reactors that employ core replacement should be assigned a lower consumable cost because the core replacement regularly replaces a large proportion of the plant parts.

    iii) Core replacement cost (if applicable): Some reactor concepts employ core-swapping (or core-replacement) schemes. It is difficult to categorize the costs associated with core-replacement as either capital or operating. The suggested method to analyze the cost of core replacements is to spread the cost equally over the plant lifetime and thus, treat core replacements as an operating cost, similar to refueling. The core replacement should be financed by continuous contributions to a core replacement fund.

    iv) Waste: Waste handling is (implicitly) included in staffing and consumables costs. The cost of on-site storage and contribution to a long-term storage fund (NWMO) is likely to be largely independent of the fuel form. The cost of long-term storage is a function of the mass, volume and shape of fuel and so is difficult to estimate. Moreover, the production of long-term waste is covered by the evaluation criteria. Though it is worth consideration at stages closer to reactor deployment, it is expected to be a small percentage of the LCOE and therefore should not affect the reactor selection.

3. **Decommissioning:** Because the cost is discounted over many decades, difficult to estimate, and largely non-discriminatory it is not specifically measured. Many cost estimates do not specify whether decommissioning is included. Similar to waste costs, it is not expected to affect the reactor selection and therefore decommissioning costs ought not to be accounted for.

The capital and operating costs are to be determined separately and added together with the appropriate discounting to obtain an LCOE value. Cost summaries should be provided on both an electrical and thermal unit basis. Most sources provide capital cost estimates on an

[65] https://cna.ca/wp-content/uploads/2014/05/MOE-Feasibility-Study_SMRs-June-2016.pdf.

electrical unit basis ($/kWe, $/MWh-e, etc.), these estimates are converted to thermal at the end. Fuel costs however must be first calculated on a thermal basis ($/kWth, $/MWh-th, etc.) and then converted to electrical. Both thermal and electrical basis cost estimates are ultimately provided because both are relevant:

- SAGD steam is generated from heat (thermal basis is the appropriate metric).
- The deployment will likely produce electricity (electrical basis is the appropriate metric).

9.7.2 Capital Cost Estimation

Multiple cost estimation methods should be explored to reduce the risk of incorrect estimates and serve as a means of verification. It is likely that a bottom-up approach cannot be adopted because, if the reactor design is even at a level of development that allows for a "line-by-line," bottom-up approach, the design details required are generally not released publicly. Therefore, a top-down approach should be adopted instead. The three cost estimation methods explored are listed below:

1. Extrapolation from LWR builds:

   The relationship between cost and capacity is extracted from historical data while the cost of a recently completed/under-construction large, light-water reactor (LWR) build is used as a reference point to develop a cost curve that is a function of capacity. This relation is referred to as the economies-of-scale effect.

   A co-siting factor is applied to account for the reduction in cost of subsequent units at the same site due to factors such as shared components, distribution of design/licensing over fewer units, and higher construction productivity through learning.[66]

   - Co-siting factor $=(1 + (n - 1)(1 - F_{ind}))/n$,
     - n = units
     - F_{ind} = indivisible costs, F_{ind} = 0.33.

2. Agnostic, reputable third-party:

   The third-party organization must provide cost estimates for (nearly) all reactor types analysed because cost estimations are very sensitive to the chosen methodology and assumptions. Intergovernmental organizations (Nuclear Energy Agency, IAEA, OECD, etc.), national laboratories (DOE labs, CNL, etc.), multi-authored university reports, and articles in peer-reviewed journals are among the literature that is acceptable. Due to the limited availability of third-party reports that include all reactor types, this estimation method is not suggested.

3. Publicly available vendor estimates:

[66] https://inldigitallibrary.inl.gov/sites/sti/sti/6293982.pdf.

Due to limited available data, for several designs, a reliable and useful estimate will likely not be found. A limited set of estimates should not be included in the interest of consistency. Therefore, it is suggested that individual estimates are not included in the LCOE calculations, yet they could be included as a useful means of checking the extrapolation method. Estimates are only consistent if the estimates are based off the same set of parameters/assumptions. It is not prudent to compare the cost estimate of one technology to another if it conducted assuming different locations or co-siting savings for instance. It is suggested to avoid rewarding designs that have overly optimistic estimate and penalizing designs that have overly conversative estimates.

9.7.2.1 *Extrapolation from LWR Builds*

Assumptions for the capital costs of SMRs calculated using the extrapolation methodology include the following:

1. Site-specific design and regulatory costs for nuclear power are included in the CAPEX.
2. Based on a successful FOAK deployment; there are no recent examples, this issue is discussed.
3. The cost estimate is independent of reactor technology, it is only a function of unit capacity and the number of units.

An often-cited approach to estimate the capital cost as a function of size is described by Carelli et al.[67], producing a capital cost estimate for SMRs based on the economies of scale of large reactors:

$$CC_{SMR} = CC_{LR}\left(\frac{P_{SMR}}{P_{LR}}\right)^{n-1}$$

Where CC_{SMR} is the SMR capital cost, CC_{LR} is the capital cost of a reference large reactor, P_{SMR} and P_{LR} are the nameplate capacities (or power) of the SMR and LR respectively. n is defined as the economies of scale exponent, determined by historical data to be between 0.5 (high economies of scale) and 0.7 (low economies of scale). n is calculated to be 0.62 in the study by Carelli et al.[67]

The approach taken to adjust for the reactor size and number of units is to determine the cost for a single reactor and the adjust the estimate to account for co-siting savings. The co-siting factor is calculated using a formula from a 2014 INL study.[68]

$$\text{Cositing} = (1 + (n-1)(1 - F_{ind}))/n$$

Where F_{ind} represents the indivisible costs. The INL study finds $F_{ind} = 0.34$, so co-siting 4 reactors – the approximate expected number of reactor units - would result in a cost savings

[67] https://www.researchgate.net/publication/223903686_Economic_features_of_integral_modular_small-to-medium_size_reactors#:~:text=A%20description%20of%20Small-Medium%20size%20Reactor%20%28SMR%29%20economic,the%20integral%20and%20modular%20design%20strategy%20of%20SMRs.
[68] https://inldigitallibrary.inl.gov/sites/sti/sti/6293982.pdf.

of 24% (co-siting = 0.76). A study by Carelli et al[67] and Ingersoll[69] suggest that co-siting effects reduce the additional expense of a 4-unit plant from 70% of a 1-unit plant to 5%; see Figure 9-3. The study by Carelli et al and Ingersoll is conducted using overnight cost and scaling from one 1340 MWe unit to 4 x 335 MWe units.[69]

- The Average value from Carelli/Ingersoll, 0.655 for a 4-unit plant corresponds to Find = 0.46.

Data from a 2011 NEA report estimates a cost reduction factor for 4 units of 0.81 – 0.9[70] and states (paraphrasing): A reduction from co-siting is quite significant but it would not be sufficient to compensate for the scaling law (i.e., economics of scale).

- The median of the NEA study, 0.855 for a 4-unit plant corresponds to a F_{ind} = 0.19.

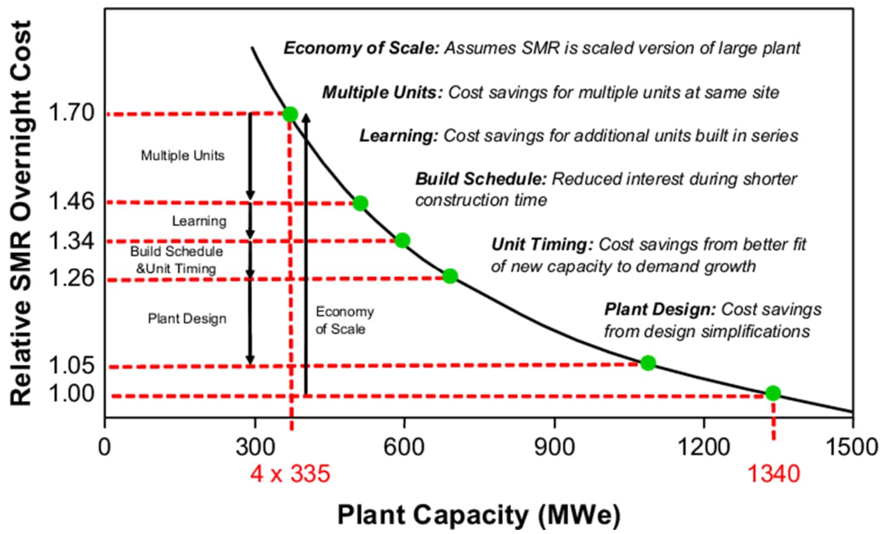


Figure 9-3: Economies of Scale and Co-Siting Effect69

Ultimately, a co-siting F_{ind} value for the co-siting formula of 0.33 is selected, the average of the 3 studies (INL, Carelli et. al. and NEA) which results in a co-siting cost savings of 25% for a 4-unit plant and a 27.5% higher cost than a single-unit plant of equal capacity.

A cost for a specific number of units with a specific capacity must be selected as a benchmark. The recency, location of construction, location of EPCM firms and construction execution were the primary factors considered in the selection of a suggested large reactor benchmark. Reactor construction costs have varied significantly over time and the analysis should consider construction in a region with comparable construction costs to Canada. The Barakah Nuclear Power Plant (United Arab Emirates) is undergoing the commencement of commercial operation of 4 units in 2021-2023. The cost was approximately $4,500

[69] https://reader.elsevier.com/reader/sd/pii/S0149197009000171?token=522BA85619DEE4F8FF93CFE70F9CDF87DA50EB5FA3146B40E8A325940DFF9A92A2A4E99AC2E947A8CC95807DD566C36D&originRegion=us-east-1&originCreation=20230417191728.
[70] https://www.oecd-nea.org/ndd/reports/2011/current-status-small-reactors.pdf.

(USD, 2018) ($6,943 CAD, 2023) per kWe capacity and the capacity of each of four reactor units is 1345 MWe. If only one unit were constructed the expected cost would be $9,226/kWe (CAD, 2023). It was constructed in desert conditions, 53 km west-southwest of the city of Ruwais.

There are limited recent nuclear power reactor builds to benchmark against. The UAE does not have comparable environmental conditions and the political/economic climate differs significantly; however, the project costs are reliable, and the project was led by Korea Electric Power Corporation (KEPCO) with most facets of deployment conducted by firms outside of the UAE. The desert conditions of the Barakah power plant likely resulted in higher costs while the construction of 3 of the units in Korea, prior to site delivery and assembly, likely served to reduce the project cost. These effects cannot be precisely quantified and are assumed to cancel out. The construction execution (budget, schedule) was generally successful. The experience of other recent builds, such as the Vogtle 3&4 or the Olkiluoto 3 reactor, have largely shown troubled project execution, with significant overruns of budget and schedule. Using either of these as the benchmark would result in unreasonably high capital cost estimates.

The results of the capital cost estimation using the extrapolation method are shown in Table 9-8.

9.7.2.2 Agnostic, Reputable Third-Party

Most SMR cost estimates by agnostic, reputable third parties only estimate the costs of SMRs generally, rather than for specific designs/technologies. This study examined a report authored by OPG, Bruce Power, NB Power and SaskPower as well as one authored by PNNL as they provide good estimates of SMR costs generally, that serve as a useful check against the other estimates. Design/technology specific recommendations from an MIT report were considered but are ultimately not included in the development of cost estimates. Some key take-aways from these reports are listed below and in Table 9-7. It provides a summary of advanced nuclear cost estimates.

- A Feasibility of SMR Development and Deployment report by OPG, Bruce Power, NB Power and SaskPower, provides an estimate of the LCOE for (a) grid-scale SMR(s) of 55 - 120 $/MWh, CAD 2021 (61 - 133 $/MWh CAD, 2023)[71]. The report points out that designs which have done more work to substantiate their cost estimates tend to have higher estimates.
- PNNL report, 2021, Techno-economic Assessment for Gen III+ SMR Deployments in the Pacific Northwest[72], referred to U.S. Energy Information Administration (EIA) data, states that the average overnight cost of advanced nuclear power is $6,317/kWe (USD, 2019)

[71] https://www.publications.gov.on.ca/CL30901.
[72] https://www.pnnl.gov/sites/default/files/media/file/PNNL%20report_Techno-economic%20assessment%20for%20Gen%20III%2B%20SMR%20Deployments%20in%20the%20PNW_April%202021.pdf.

($9,651 CAD, 2023) and O&M (both fixed and variable) is $25/MWh ($38/MWh CAD, 2023).

- **MIT Study, 2018: The Future of Nuclear in a Carbon Constrained World**[73] (Throughout study: $1 USD 2018 = $1.6 CAD 2023) Key findings:
  - "Detailed cost breakdowns for LWRs, HTGR and SFR, show that the nuclear reactor and turbine islands do not dominate the costs of these advanced systems. Costs are dominated by civil works, structures, and buildings … and associated indirect costs."
  - "…differences between the cost estimates for different advanced reactor concepts are not considered substantial or meaningful."
  - The ratio in the actual cost compared to cost estimates of different classes is shown in Figure 9-4. Few examples of recent Nuclear Power Plant cost estimate progressions exist, two are shown for Nuscale and the AP1000. This pattern was originally found by (Merrow, Phillips, and Myers 1981), in the cost growth of large engineering megaprojects (chemical, public works, and nuclear weapons) over 35 years ago.
  - The report investigated the ratio in cost estimates of different classes of nuclear reactor programs over time as shown in Figure 9-4. This figure compares examples of recent Nuclear Power Plant cost estimate progressions including those for the NuScale VOYGR and the Westinghouse AP1000 plants. A similar pattern was originally observed by (Merrow, Phillips, and Myers 1981) in the cost growth of large engineering megaprojects (chemical, public works, and nuclear weapons) over 35 years ago. In Figure 9-4., the specific data points represent the mean values associated with the project estimates noted in the legend. The uncertainty bars represent the standard deviation of all projects examined in the study along with the mean value of all projects investigated.

[73] https://energy.mit.edu/wp-content/uploads/2018/09/The-Future-of-Nuclear-Energy-in-a-Carbon-Constrained-World.pdf.

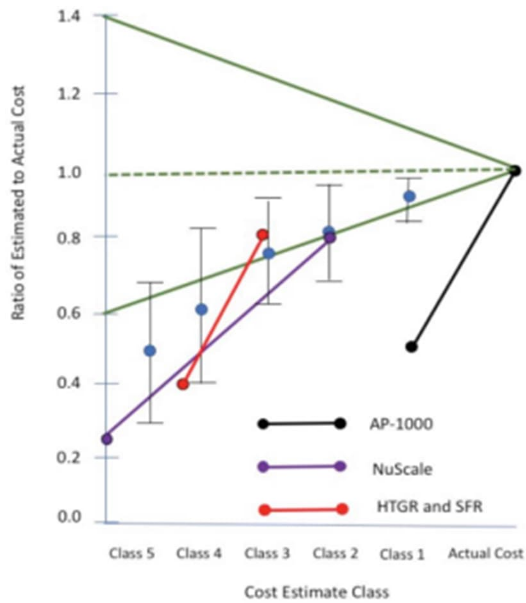


Figure 9-4: Ratio of Estimated to Actual Costs as a Function of Cost Estimate Class73

Table 9-7: Third-Party Cost Estimate Summary

Report Author	Capital Cost ($/kWe)	LCOE ($/MWh, CAD, 2023)
OPG, Bruce Power, NB Power and SaskPower	Base (i = 6%, capital costs = 70%): ~$5,740 to ~12,500 Inflated (class 4): ~$9,570 to ~20,800	Base: $61 to 133 Inflated: ---
PNNL	Base: $9,651 Inflated (class 4): $16,085	Base: --- Inflated: ---
MIT	Base: ~$7,760 Inflated (class 4 & size/co-site adjusted): ~$18,000	Base: --- Inflated: ---

All three reports do not explicitly mention that the cost estimates take into consideration the phenomenon of realized costs exceeding prior cost estimates. Moreover, adjusting the cost estimate higher relative to the level of precision (class) is not known to be common practice, so it is presumed that the estimates do not include an upward adjustment to reflect the difference in realized and estimated cost. That difference is accounted for in the 'inflated' values provided in Table 10 23. The inflated values are both similar to each other and similar to the LWR extrapolation overnight capital costs.

9.7.2.3 *Capital Cost Summary*

Table 9-8 shows the relative estimated capital cost for the generic 33,000 barrels/day SAGD operation described in Section 4 which would require approximately 362 MWth (145 MWe equivalent at 40% efficiency), the 4-year construction cost is calculated with a discount rate of 10%. A precise capital cost estimate is difficult to make at this stage, so costs are shown relative to a deployment with three 50 MWe reactors (three 50 MWe = reference case, costs shown in Table 9-8 are a percentage of the reference case).

Table 9-8: Capital Cost Summary (CAD, 2023), Costs shown relative to 3x 50 MWe Reference Case (3x 50 MWe = 100%)

MWe[74]	Expected No. of Units[75]	Overnight cost, 1 unit (% of ref./kWe)	Co-siting Factor	Overnight cost, all units (% of ref./kWe)	With 4 Year Constr. (% of ref./kWe)
50	3	105.4	78.0%	82.2	100.0
70	2	92.7	83.5%	77.4	94.2
100	1	81.0	100%	81.0	98.5
150	1	69.4	100%	69.4	84.4

9.7.3 *Operating Cost Estimation*

Operating costs are estimated using a combination of fuel, staffing costs and consumables. Some reactors may also include a core replacement cost. This estimation approach can be more detailed than with capital costs because of the data available. Non-staff operating costs, or consumables (replacement parts, safety equipment, etc.) are the most difficult to estimate – the suggested strategy is simply to add an annual operating cost equal to a percentage of the overnight capital cost. This strategy has been previously employed in past studies including a 2014 Hatch study for the Ontario Ministry of Energy.[76]

9.7.3.1 *Fuel Cost*

Fuel Costs can be divided in 4 Component Costs.

1. Uranium ore extraction (Uranium oxide, U_3O_8, concentrate price).

[74] All cost data is provided in MWe. The costs data is not adjusted to thermal efficiency because high efficiency reactors generally have less OPEX and so can be expected to have somewhat higher costs per MWth, all else being equal.
[75] Including for power production.
[76] https://cna.ca/wp-content/uploads/2014/05/MOE-Feasibility-Study_SMRs-June-2016.pdf.

Spot and long-term uranium prices (2000-2021) (Source: Cameco, UxC, TradeTech)

Figure 9-5: Uranium Oxide Concentrate price, Nominal USD77

- In recent years, the cost of uranium in long-term contracts has fluctuated between $35 and $40. Past data indicates extended periods of time both above and below this price. Conservatively, the higher value, $40/lb (USD, 2021) is suggested as an input to fuel cost estimates.

2. Conversion:

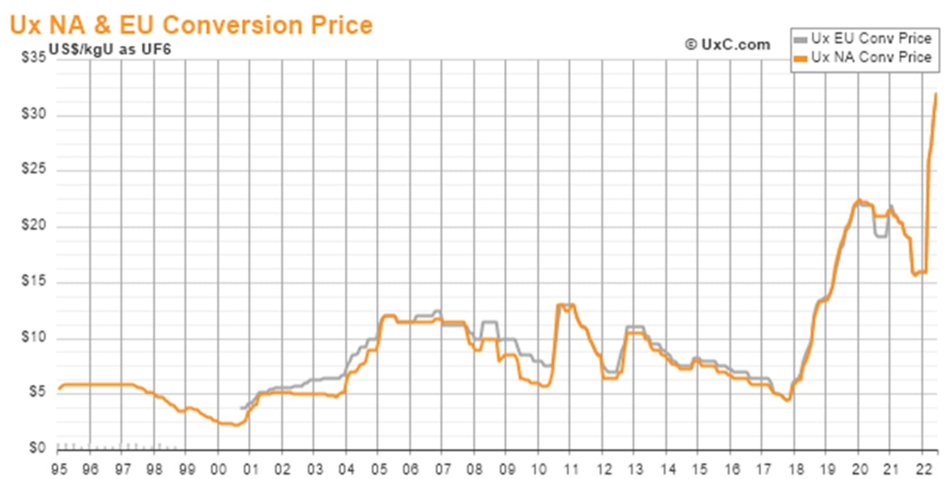


Figure 9-6: Conversion Price Nominal USD, from Ux78, through Equity Guru

The conversion cost is historically high in recent times because of tight supply exacerbated by geopolitical tension between Russia and Ukraine. Because prices currently exceed

[77] https://world-nuclear.org/information-library/nuclear-fuel-cycle/uranium-resources/uranium-markets.aspx.
[78] https://www.uxc.com/p/prices/UxCPrices.aspx?currency=eur.

production costs by a considerable margin, the long-term price is likely to average a lower value. A price of $15/kgU (USD, 2022) is suggested as an input to fuel cost estimates.

3. Enrichment:

Table 9-9: Enrichment Prices, Nominal USD79

Year	2007	2009	2011	2013	2015	2017	2019	2021
Price ($/SWU)	115	131	136	142	137	125	110	100

The cost of enrichment is measured in units of Separative Work Units (SWUs). Separative work is the amount of separation done by an enrichment process and SWUs are technically measured in units of kilograms, though in practice are a measure of the energy required for isotope separation. It takes approximately 9 SWUs to produce 1 kg of PWR or BWR nuclear fuel.

4. Fuel fabrication:

Table 9-10: Fuel Fabrication Costs

Fuel Type	Fabrication Cost, $/kgU (USD, 2010)	Fabrication Cost, $/kgU (CAD, 2023)
Low enriched oxide fuel	270	494
TRISO (incl. fuel compact & block or pebbles)	10,000	18,300
Metallic fuel	718	1314

The INL study[80] on advanced fuel cost is used to establish fuel fabrication costs. The reference values are shown in Table 9-10. Given the high uncertainty in the advanced fuel cycle, the costs in the report are not adjusted further.

Table 9-11: Component Cost used in Fuel Cost Calculations

Component Costs	Value [CAD, 2023]
Uranium concentrate	59/lb ($130/kg)
Conversion	21/kgU
Enrichment	207/SWU

Total fuel costs should be calculated on a per kilogram basis using the Uranium Ore, Conversion, Enrichment and Fuel Fabrication cost estimations in Table 9-10 and Table 9-11.

79 https://www.eia.gov/uranium/marketing/summarytable2.php.
80 https://fuelcycleoptions.inl.gov/Shared%20Documents/2009_Advanced_Fuel_Cycle_Cost_Basis.pdf.

9.7.3.2 *Staffing*

Some SMR vendors claim that they plan to operate the plants remotely without any on-site operators. These claims cannot be verified at this stage and in Hatch's judgement are unlikely to be implemented. The actual calculation of minimum staff complement (MSC) is a complex task requiring a systematic analysis based on events identified in safety reports (including single and multi-unit station cases), credited operator actions, credible events in the PSA, emergency operating procedures and operating strategies. Due to the lack of OPEX, the staff complement is estimated in a technology independent fashion. The number of staff attending to the nuclear island is expected to far exceed the number attending to the SAGD tie-in/interface and the SAGD tie-in/interface staffing requirements are difficult to estimate. Moreover, staff involved in electricity production are generally included in nuclear power plant staffing estimates and the SAGD tie-in/interface is expected to require roughly the same staff complement. It may be possible for current SAGD steam plant operators to serve functions in the operation of the nuclear plant as well. The extent of staffing savings through the current SAGD operation is difficult to quantify, expected to be quite limited and therefore assumed to be negligible.

In a 2014 Hatch study for the Ontario Ministry of Energy[81] the operator requirement is estimated using benchmark data points extracted from an IAEA report[82]. A non-linear curve was fitted to the data using the following constraints:

- For the smallest reactor, 1 operator per shift is assumed. In addition, 3 shifts and 5 rotating teams are assumed to ensure operator availability at all times. Thus, the minimum number of operators was assumed to be 5 per site regardless of the plant size.
- The number of operators per MW should decrease for larger plants due to the economies of scale effect.

The number of operators was selected based on regression analysis and is described by the following function:

$$Number\ of\ Operators = a - b \cdot e^{-c \cdot (Reactor\ Power\ in\ MWe)^d}$$

Where the coefficients are a = 7.858E+2, b = 7.815E+2, c = 9.153E-4 and d = 7.222E-1.

In the same IAEA report[82], data suggests that total number of staff is approximately 10x greater than the number of operators. Other staffing requirements in an SMR deployment includes administration/support, maintenance, engineering, safety, and site services. Moreover, the relation between the number of staff and the plant size is similar regardless of staffing type (operations, maintenance, engineering, etc.) As a result, the total number of staff is estimated to equal 10x the estimated number of nuclear operators.

[81] https://cna.ca/wp-content/uploads/2014/05/MOE-Feasibility-Study_SMRs-June-2016.pdf.
[82] https://www-pub.iaea.org/MTCD/Publications/PDF/te_1052_prn.pdf.

It is assumed that the economies of scale effect found in the IAEA data is dominated by reactor size rather than co-siting, for several reasons:

- Approximately 300 people were employed full-time during the operational phase at Point Lapreau[83] [pg. 11] compared to the number of Bruce power employees (over 4000[84]), suggesting that co-siting has only a small impact on the number of employees.
- The operational co-siting benefit in modern nuclear power plant operations is n = 0.88.[85]
    - $Cost = (cost\ of\ 1\ reactor) \cdot (no.of\ reactors)^n$.
- There is more variance in reactor size than number of units in the IAEA data.

The effect of co-siting is still significant, so the benefit is taken into account using the co-siting equation with n = 0.88 and reflected in Table 9-12. The number of staff for a multiple reactor deployment is estimated to be equal to the summation of:

- The minimum staff for a 0+ MWe plant.
    - The following equation finds a minimum of 50 staff for 0+ MWe plant: $Total\ staff = operators = 10 \cdot (a - b \cdot e^{-c \cdot (0)^d}) = a - b = 50$. This number is applied to all reactor designs.
- The number of staff per reactor beyond the minimum staff for a 0+ MWe plant multiplied by the number of reactors.
    - $Staff\ per\ reactor\ beyond\ minimum = 10 \cdot [a - b \cdot e^{-c \cdot (MWe)^d} - (a - b)]$.

To determine a cost per MW, the average annual cost per full-time employee is required. The selected value is $150,000 CAD.

Table 9-12: Number of Staff and Consumables

MWe[86]	Expected No. of Units	Co-Siting Factor	Total Staff	Staff/ MWh-th	Staff: $/MWh-th	Consumables $/MWh-th
50	3	87.6%	352	0.94	16.94	5.74
70	2	92.0%	320	0.91	16.47	5.41
100	1	100.0%	240	0.96	17.27	5.66

83 https://www.saskpower.com/-/media/SaskPower/Our-Power-Future/Our-Electricity/Nuclear-Studies/Report-SupplyOptions-Nuclear-EconomicEffects-1993.ashx.
84 https://www.brucepower.com/who-we-are/meet-our-people/#:~:text=Bruce%20Power%20has%20over%204%2C000,and%20outside%20the%20nuclear%20industry.
85 https://re.public.polimi.it/retrieve/handle/11311/547748/270163/COMPETITIVENESS%20OF%20SMALL%20MEDIUM%2C%20NEW%20GENERATION%20REACTORS%20A%20COMPARATIVE%20STUDY%20ON%20CAPITAL%20AND%20O%26M%20COSTS.pdf#:~:text=Smaller%20size%20reactors%20are%20going%20to%20be%20an,time.%20The%20IRIS%20reactor%20is%20used%20as%20the.
86 The IAEA data is provided in MWe. The staffing requirements are not adjusted to thermal efficiency because high efficiency reactors are generally less OPEX and so can be expected to have somewhat higher staff complements per MWe, all else being equal.

150	1	100.0%	305	0.81	14.67	4.85

9.7.3.3 Additional Discussion Including Core Replacement

Similar to capital costs, operating cost estimates from third-party sources or the vendors are not incorporated into the LCOE calculations. To determine the replacement fund cost: (1) The total overnight capital cost is multiplied by the fraction of capital cost (2) The cost is converted from a capital to a levelized cost. Approximately a 60-year economic lifetime should be assumed for designs employing core replacements schemes as well.

9.7.4 Cost Summary

Table 9-13, is a summary of the results at reference conditions, capital costs account for the increase in real costs resulting from a non-zero construction time, operating costs include core replacement costs and the LCOE is calculated using a discount rate of 10% and an economic lifetime of 60 years. Table 9-14 shows the LCOE at a low (6%), medium (8%) and high (10%) discount rate. Precise capital cost and LCOE estimates are difficult to make at this stage, so costs are shown relative to a deployment with three 50 MWe reactors.

Table 9-13: Summary of the Calculated LCOE Values at Reference Conditions, Capital and LCOE Shown Relative to 3x 50 MWe, i = 10% Case (50 MWe, 10% = 100%)

MWe	Expected No. of Units[87]	Capital, % of ref./kWe	Capital, % of ref./kWe	Operating, $/MWh-e	Operating, $/MW-th	LCOE-e, % of ref.	LCOE-th, % of ref.
50	3	100.0	40.0	~70	~$30	100.0	40.0
70	2	94.2	37.7	~70	~$30	94.7	37.9
100	1	98.5	39.4	~70	~$30	98.9	39.6
150	1	84.4	33.8	~65	~$25	85.2	34.1

Table 9-14: LCOE Sensitivity to Discount Rate, LCOE Shown Relative to the 3x 50 MWe, i = 10% Reference Case

MWe	Expected No. of Units[88]	LCOE-e, % of ref.			LCOE-th, % of ref.		
		i = 6%	i = 8%	i = 10%	i = 6%	i = 8%	i = 10%
50	3	67.9	83.7	100.0	27.2	33.5	40.0
70	2	64.5	79.3	94.7	25.8	31.7	37.9
100	1	67.3	82.8	98.9	26.9	33.1	39.6
150	1	58.1	71.4	85.2	23.2	28.6	34.1

[87] Including for power production.
[88] Including for power production.

9.8 Selection of Final Technologies

The process of further down selecting technologies that may pass the intermediate stage is informed by evaluation criteria (Pugh matrix), TRL, PSRL and LCOE. Each of these metrics yields a single, numerical score that makes clear the difference in relative suitability.

The results should be analyzed in three formats:

1. The unrefined scores, with no adjustment or ranking.
2. A ranking of the scores. Although it removes some detail it provides clarity.
3. The rankings should be further clarified by making several adjustments in an attempt to more accurately and clearly communicate the differences between scores.
   - Similar scores should be combined into the same rank. This makes the scores easier to interpret as it highlights the consequential differences.
   - If large differences in the scores of components exist, then gaps in the rankings should be introduced to communicate that the scores differ more substantially.

A very poor score on any one of the components should generally be avoided – only very compelling scores on the other 3 metrics should keep a particular design under consideration for selection:

- The evaluation criteria are generally a measure of how well the reactor integrates with the facility (SAGD production, electricity production, the desired schedule, and the physical site). A deployment would face numerous difficulties and integration costs if it fit very poorly.
- The TRL is effectively a measure of the magnitude of time, expense and risk associated with bringing the reactor on-line. If this metric is scored very low, the risk that the owner would be taking on must be very high.
- The PSRL effectively measures the ability of the proponent firms to deploy (design, construct and operate) a reactor design. Similar to TRL, a low score means that the owner would be taking on a high risk.
- The importance of LCOE does not need to be elaborated upon.

As a result of the desire to avoid a very poor score, the following selection procedure has been developed. This selection procedure is intended to serve as a guideline, Hatch does not recommend that it is followed to the letter. The procedure described is for the selection of two designs for further evaluation, but it could be applied to just 1 or more than 2 designs.

1. Select the component which is most important.
2. Eliminate designs that perform substantially lower than average on that component or perform poorly on multiple components.

3. At this point there should be a very small number of designs left (no more than 4). Identify the design that is most promising from the remaining options.
4. Repeat as required with the remaining components to arrive at 2 remaining designs.
5. From the two designs, identify the components in which there is a significant difference in score and through careful consideration select one reactor as more promising to be examined further. No rigorous procedure is provided for this step because it is design-specific and depends on the trade-offs involved.

If the deployment scenario produced both electricity and SAGD steam, then both the LCOE-electricity and LCOE-heat are consequential to the selection. The relative difference between the LCOE scores may differ because of different efficiencies – a reactor with high thermal efficiency may have a lower LCOE-electricity but higher LCOE-heat than a reactor with a lower thermal efficiency. A method has been devised to combine the consequence of both while considering the efficiency differences:

$$LCOE_{t,eff} = (0.4(n_e LCOE_e) + n_t LCOE_t)/(n_e + n_t)$$

Where an efficiency of 40% (0.4) is assumed and n_e is the number of power generating and n_t the number of SAGD steam generating units.

9.9 Technology Assessment and Down Selection: Summary & Conclusions

An outline of a methodology and a discussion of considerations for the down selection of one or a small number of technologies (i.e., reactor designs) for further evaluation has been conducted. The technology evaluation methodology follows a phased approach. First a comprehensive list of all SMR designs is compiled and using the evaluation criteria of, Country of Origin, SMR Modular Size (upper and lower bound), Corporate Design & Maturity, Application and Reactor Technology, the initial list is then screened down to 24 technologies. This list should then be further narrowed down to reactor designs that have a realistic chance of being selected. Hatch's proprietary evaluation methodology was applied to the narrowed down designs. It consists of 4 components:

- Technology Compatibility Assessment: This component involves the development of a Pugh (or 'decision') matrix consisting of criterion generally related to site-specific integration considerations.
- Technology Readiness Assessment: It is a scoring of the Technology Readiness Level (TRL).
- Proponent Strength and Readiness Assessment: the three proponents are the Licence Applicant, Technology Vendor and EPC/EPCM partners.
- Levelized Cost of Energy (LCOE): The LCOE estimation is conducted in largely a technology, configuration and location agnostic manner, where costs are a function of reactor capacity (economies of scale) and number of units (co-siting).

The evaluation concludes with the selection of the final technology(s), considering the assessments of all four components. The analysis is based on a Generic SAGD site which requires 18 MWe of power and 362 MWth of heat.

10. Licensing and Regulatory Approvals for Nuclear Power

10.1 Overview

The use of nuclear energy is subject to a rigorous regulatory regime that plays a significant and deterministic role in its deployment, from conceptual study through to construction, operations and eventual decommissioning and closure. Schedule delays and long approval timelines are a common risk for capital-intense, innovative industrial developments, and nuclear power is no exception to this. To understand the predominant regulatory aspects of building and operating this type of facility, an overview of the licensing and regulatory approvals is provided in this section.

In Canada, nuclear energy is solely regulated by the federal government through the Canadian Nuclear Safety Commission (CNSC), however non-nuclear considerations of a nuclear-powered facility are also regulated by a variety of federal, provincial/territorial, and municipal or local governments and agencies. Three sequential licences granted by the CNSC, and at least one environmental impact assessment review[89] and additional provincial approvals, will be required to begin commercial operation of an SMR in Alberta. Obtaining these licences and completing the federal impact assessment process are likely to be critical path for successfully introducing nuclear power into Alberta's oil and gas sector; as such these requirements are the focus of Hatch's analysis and summary for this section. Requirements and considerations for how the province might seek to regulate important non-nuclear aspects are also discussed.

As deployment of a nuclear power plant has never been undertaken in the province, there are first-of-a-kind (FOAK) considerations bringing both uncertainty and opportunity to the expected governance framework employed by Alberta. Uncertainty can result in increased timelines for proponents seeking to build an SMR, however by undertaking a review of current policy and associated requirements for building and operating a nuclear-powered facility in the short term, the Government of Alberta is well positioned to become a leader in the deployment of SMRs to [presently] non-nuclear jurisdictions. As it exists today, Alberta's regulatory framework must evolve to accommodate this novel energy source if deployment is expected before 2035. Clarity in the approvals framework, process, timelines, and authority will support a timelier introduction of nuclear power, so it is imperative that provincial policy be assessed for this purpose within the immediate future. Nonetheless, the Government of Canada has repeatedly signaled its readiness for the emerging use of SMRs across the country and is committed to ensuring the safe use of nuclear energy for the next generation of reactors.

[89] A federal Impact Assessment is required for nuclear facilities with an output of >200 MWth; a provincial review is expected but this requirement has not been tested.

10.2 Federal Regulatory Approvals

The CNSC is Canada's nuclear energy regulator. It is an independent, quasi-judicial administrative tribunal providing advisory services to Parliament through the Minister of Natural Resources. This is a unique aspect of the CNSC among its federal counterparts. It is important to note the CNSC is not accountable to any federal minister, and maintains a legislated, arms-length independence from government. This relationship has been enacted to ensure that the Commission remains free from political influences and is a central aspect to safely regulating nuclear energy in Canada. This model is used around the world and is considered to be the "gold standard" among the world's leading nuclear regulators.

Through the CNSC and additional federal agencies such as Natural Resources Canada and the Impact Assessment Agency of Canada, the federal government has established a comprehensive legislative framework that focuses on protecting the health, safety and security of Canadians and the environment associated with the use of nuclear energy. The more significant pieces of federal legislation that apply to the nuclear industry are outlined in Table 10-1.

Of the legislation presented in Table 10-1, two are primary acts governing deployment of nuclear power facilities: (1) the *Nuclear Safety and Control Act* (NSCA) and its corresponding *Class I Nuclear Facilities Regulations*, and (2) the *Impact Assessment Act* (IAA) and its corresponding *Physical Activities Regulations*.

Table 10-1: Canada's Main Legislation for Regulating Nuclear Power

	Governing Legislation	Intent	Delegated Authority	Application
Nuclear Energy and Substances	*Nuclear Safety and Control Act*	Establishes the CNSC with the authority to regulate the development, production and use of nuclear energy and other nuclear sector activities	Canadian Nuclear Safety Commission (CNSC)	Establishes licensing basis needed to safely site, build, and operate a nuclear power plant in Canada
	Nuclear Fuel Waste Act	Establishes oversight for long-term management of used nuclear fuel, clarifies role of the Nuclear Waste Management Organization (NWMO)	Natural Resources Canada (NRCan)	Companies that generate used nuclear fuel are required to set aside funds covering the cost of its long-term management, which is led by the NWMO; a storage facility is expected to be operating in the early 2030s and management of non-

	Governing Legislation	Intent	Delegated Authority	Application
				CANDU fuel will be included in the facility design
	Nuclear Liability and Compensation Act	Establishes compensation and liability regime in the unlikely event of a nuclear accident resulting in civil injury and damages	Natural Resources Canada	Operators of nuclear facilities require insurance from approved brokers to guarantee compensation for civil damages arising from an accident. Each operating plant in Canada currently holds $1B in liability
Environment	*Impact Assessment Act*	Establishes the process and governance for proponents to predict and control significant negative environmental, health, social, and economic impacts of large developments before they can proceed; positive effects are also assessed	Impact Assessment Agency of Canada[90] (IAAC)	Beginning in June 2019, proponents of nuclear power plants > 200 MWth must complete an impact statement that is jointly reviewed by the IAAC and CNSC. The Minister can also refer smaller sized SMRs to complete this if significant adverse impacts are expected. If there is strong public opposition to a proposed nuclear power plant, the project could be rejected under this Act
	Canadian Environmental Protection Act	Provides pollution prevention and the protection of the environment and human health in order to contribute to sustainable development	Environment and Climate Change Canada (ECCC)	Sections of this Act establish thresholds for the regulation of hazardous substances used in the nuclear industry

[90] For projects on federal lands that are funded through NRCan, this agency is also required to evaluate the environmental effects under the Impact Assessment Act.

Governing Legislation	Intent	Delegated Authority	Application
Fisheries Act	Establishes protections for Canada's fish and fisheries	Fisheries and Oceans Canada[91] (DFO)	If a project occurs near or in water, the proponent can submit the project plans to Fisheries and Oceans Canada (DFO) for review of impacts and allowable activities. For project activities that are determined to be prohibited under this Act as they may result in the death of fish or harmful alteration, disruption, or destruction of habitat, the DFO Minister may issue a Fisheries Act Authorization (FAA) under Sections 34.4(2)(b) and 35(2)(b) of this Act to allow the activity to proceed if mitigations are acceptable
Migratory Birds Convention Act	Establishes broad protections for numerous bird species in Canada	Environment and Climate Change Canada	Development activities must be managed to prevent impacting migratory birds, nests and eggs; this can often impede activities scheduled to occur during Apr – Sept when migratory birds are present in Northern Alberta, with the exception of the Pileated Woodpecker that has been granted year-round

[91] ECCC is responsible for aspects of this Act related to the deposit of deleterious substances into waters frequented by fish.

	Governing Legislation	Intent	Delegated Authority	Application
				protections of its nesting or roosting cavities
	Species at Risk Act	Canada's main conservation tool to protect rare species, maintain healthy ecosystems and preserve natural heritage	Environment and Climate Change Canada	If a species is listed under this Act, there can be associated areas protected from development (critical habitat), and activities that could impact these species or their habitats might need to be curtailed
Transportation	*Navigation Protection Act*	Provides protection to preserve the navigability of Canada's waterbodies	Transport Canada	Water inlets and outlets for nuclear power installations need to ensure navigability is maintained on recognized waterbodies.
	Transportation of Dangerous Goods Act	Promotes public safety in the transportation of dangerous goods, including radioactive materials.	Transport Canada	Applies to the transport of radioactive materials, including the movements of nuclear fuel
Occupational Health and Safety	*Canada Labour Code*	Applies to all industries over which the federal government has jurisdiction – including the nuclear industry.	Employment and Social Development Canada	Due to the elevated safety requirements for nuclear power, all currently operating NPPs in Canada are exempt from Parts I, II, III of this Code. Exemptions are not automatic and must be sought by an owner or operator/licensee.

Under the NSCA, nuclear power reactors are categorized as a Class IA nuclear facility:

> *"Class 1A nuclear facility means any of the following nuclear facilities:*
>
> *(a) a nuclear fission or fusion reactor or subcritical nuclear assembly; and*
>
> *(b) a vehicle that is equipped with a nuclear reactor."*

All Class I nuclear facilities require an analogous set of licences to reach commercial operation (Figure 10-1).

Under the IAA, proposed SMR facilities may be required to complete a federal Impact Assessment if they exceed certain generating capacity thresholds as outlined below.

> *"The site preparation for, and the construction, operation, and decommissioning of, one or more new nuclear fission or fusion reactors if:*
>
> *(a) that activity is located within the licensed boundaries of an existing Class IA nuclear facility and the new reactors have a combined thermal capacity of more than 900 MWth; or*
>
> *(b) that activity is not located within the licensed boundaries of an existing Class IA nuclear facility and the new reactors have a combined thermal capacity of more than 200 MWth."*

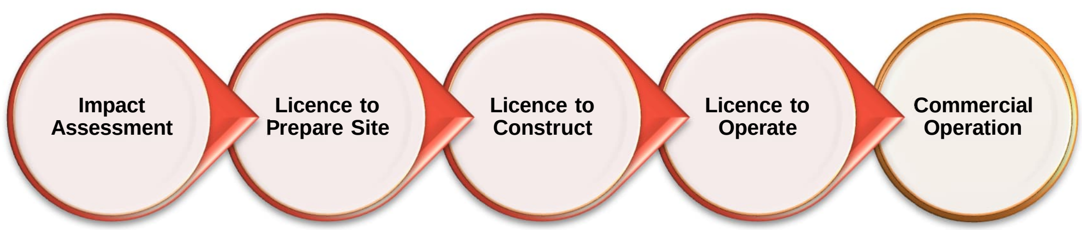


Figure 10-1: Federal Approvals Needed to Begin SMR Operation

For the SMRs under consideration in this present study, all are expected to exceed the 200MWth capacity. Therefore, an impact assessment will be required to ensure that no significant adverse environmental, health, social, and economic impacts will occur as a result of construction and operations. This impact assessment is a lengthy and semi-novel regulatory requirement, having replaced the former federal environmental assessment process previously required by the NSCA and governed by the CNSC.

The remainder of Section 10.2.1 first outlines licensing and then covers the impact assessment process. Following this, a fulsome roadmap for federal and provincial environmental reviews is provided in Section 11.4.2.

10.2.1 Licensing Small Modular Reactors

The CNSC's regulatory framework consists of Acts passed by Parliament that govern the regulation of Canada's nuclear industry along with regulations, licences, and regulatory documents that the Commission uses to oversee the industry (Figure 10-2). The CNSC uses a combination of these internal and other external guidance on best practices, and domestic and international standards (i.e., CSA Standards). This section provides an overview of the licences, the licensing process and context for how the Commission makes licensing decisions.

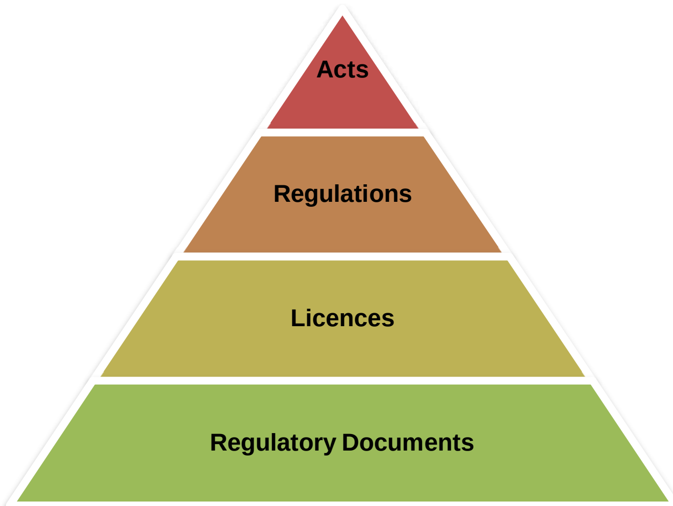


Figure 10-2: CNSC's Regulatory Framework

Under the NSCA and its regulations, the CNSC requires nuclear power plant proponents or operators[92] to obtain five licences across the plant's full lifecycle. These five lifecycle licences are:

6. **Licence to Prepare Site:** To conduct site preparation works and complete construction activities that do not include nuclear-specific components (i.e., the reactor, and its supporting infrastructure) the site preparation licence is required. This prepares a location and the prospective licensee for full, future construction and operation of a nuclear facility however the licence will only address activities for site preparation. To receive this authorization, detailed design information is not required but sufficient information must be provided to demonstrate that the applicant's organization can safely manage site preparation; this paves the way for the licensee and eventually, the facility is capable of becoming a nuclear operator and a safely operating facility.

[92] *In Canada's existing nuclear power plants, the operators, and not necessarily the owners, are also the current licensee. Whichever organization becomes the licensee is up to the SMR project proponent, however a licence will only be granted if the CNSC believes the organization can safety fulfill its obligations.*

7. **Licence to Construct:** This is required for a licensee to "construct, commission, and operate some components of the facility".[93] A construction application must include detailed information about the facility's design and safety case, address follow-up activities identified during the IA process, and confirm that any outstanding issues identified during the site preparation stage have been resolved. Under this licence, initial commissioning activities can be approved if adequately addressed by the licensee in their application.

8. **Licence to Operate:** This allows a licensee to "complete final commissioning activities and to operate the facility"[94] and is required before commercial operation of the facility can begin. For new nuclear facilities, operation commences when fuel is loaded and is typically issued with conditions known as hold points that are removed once all relevant commissioning tests are completed to the satisfaction of the regulator. This licence application must also include a conceptual decommissioning and reclamation plan and a financial guarantee for closure.

9. **Licence to Decommission:** A CNSC decommissioning licence is required to begin closure activities during the final phase of a nuclear facility once commercial operation ceases. This phase is expected to include the full disassembly, closure, and removal, etc. of all infrastructure and could take multiple years to complete. Environmental monitoring to demonstrate the safety of the site continues through this licensing phase.

10. **Licence to Abandon:** Upon completion of decommissioning activities, if the site is to be abandoned and environmental conditions are acceptable to the CNSC, a Licence to Abandon is issued. The application must include results of environmental monitoring programs that clearly establish the acceptable conditions of the site. Once abandoned, the licensee is resolved of all liability for the site and ownership of the land can be transferred to the government or other entity.

To begin commercial operation of a nuclear power plant, a prospective licensee must first complete an impact assessment, and then sequentially obtain site preparation, construction, and operating licences. The governance process for obtaining each licence is virtually identical and is shown in Figure 10-3. Licensing is formally initiated when the CNSC receives a proponent's application; this is reviewed for completeness prior to being accepted for Commission review. Based on Hatch's experience, it has been observed that for new, prospective licensees with generally low levels of organizational maturity, this completeness review process can be lengthy (i.e., 3 - 4 years or more). For new (potential) licensees with robust levels of organizational maturity, this step should be shorter however will require significant resources in shifting to a nuclear-compliant company. Deciding whether to simply

[93] *Canadian Nuclear Safety Commission. 2022. REGDOC-1.1.2, Licence Application Guide: Licence to Construct a Reactor Facility. http://www.nuclearsafety.gc.ca/eng/acts-and-regulations/regulatory-documents/published/html/regdoc1-1-2-v2/index.cfm.*

[94] Canadian Nuclear Safety Commission. 2022. REGDOC-1.1.2, Licence Application Guide: Licence to Construct a Reactor Facility. http://www.nuclearsafety.gc.ca/eng/acts-and-regulations/regulatory-documents/published/html/regdoc1-1-2-v2/index.cfm.

purchase the energy from a licensed operator, or to become the nuclear licensee will need to be assessed carefully.

Although licences must be obtained in a sequential manner, they can be applied for in a combined fashion, this is expected to reduce the length of review time. For example, a combined site preparation and construction licence, or a combined construction and operating licence can be submitted to the CNSC. Deciding to combine licence applications would generally depend on an applicant's internal commercial environment and business case such as: the completeness of the reactor design, the applicant's ability to finance the development phase of a nuclear power plant, the risk tolerance of the applicant, the required in-service date, and other factors. It is anticipated that as SMR designs become standardized and a fleet of units is established across Canada and the world, future applicants will submit combined site preparation, construction, and operating licences for review by the CNSC. Regardless of whether a single or combined licence application is received, the Commission will make separate decisions for each licence in compliance with the NSCA, however will streamline its review activities as needed; for example, it could hold joint public hearings on combined applications.

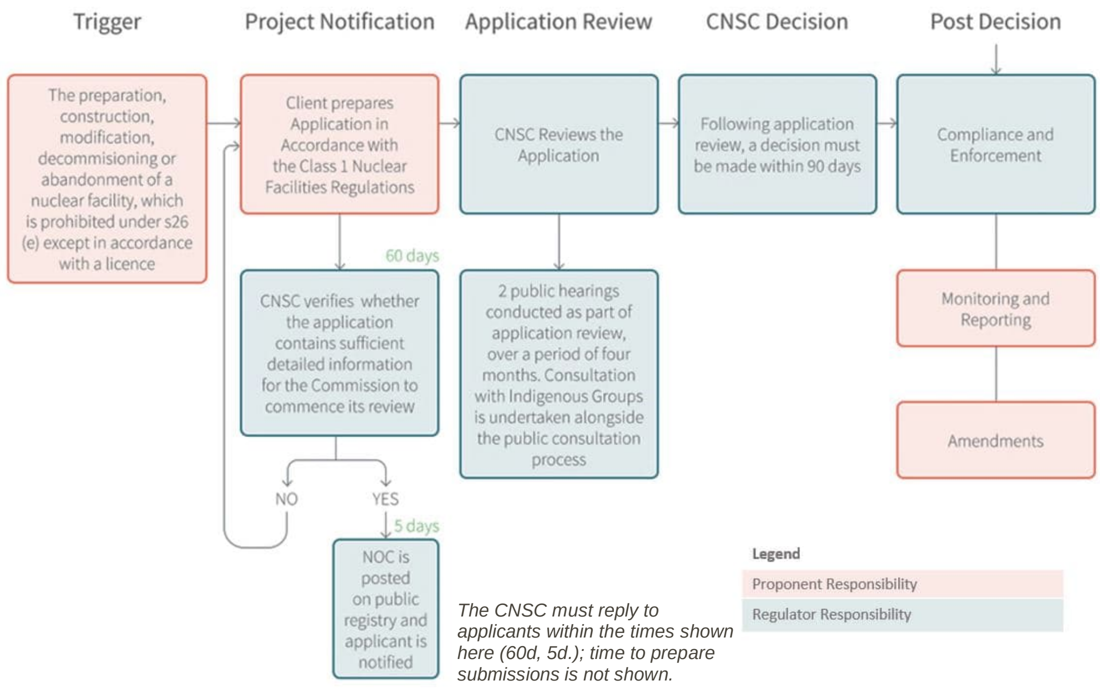


Figure 10-3: CNSC Licensing Process under the Nuclear Safety and Control Act

For all licensing reviews, extensive pre-planning and engagement with the regulator should be undertaken before initiating the formal process. This allows both parties time to prepare with a focus on achieving alignment regarding the review process.

During licence reviews, CNSC staff conduct technical assessments to determine if both the application and the proponent can meet all legislated requirements, CNSC requirements and expectations, international and domestic standards, and applicable international obligations. If a licence applicant fails to demonstrate it has the capacity, knowledge, controls, and financial resources to safely carry out its proposed activities, a licence application will be denied. The CNSC will also consult with other federal and provincial government departments, including those regulating health and safety, environmental protection, emergency preparedness, and the transportation of dangerous goods (Table 10-1). However, only the Commission can make a licensing decision.

Table 10-2 provides an overview of information required in each licence application.

Table 10-2: General Licence Application Requirements

Category	Required Information
Identification and contact information	• Applicant name address and proof of legal status • All persons authorized to represent the applicant through the licensing process • Evidence that the applicant is the owner of the site, or has the authority from the owner to carry out activity to be licensed • Identification of persons responsible for management and control of the licensed activity • Legal signing authority, billing contact authority
Facility and activities to be licensed	• Licence period (CNSC typically recommends a 10-year period) • Statement of the main purpose • Description of the site • The facility's existing licensing status (if any) • Nuclear materials and hazardous substances
Other relevant information	• Additional permits, certificates and licences • Similar facilities (if any)

Prior to granting any licence, the CNSC evaluates how well an applicant meets regulatory requirements and CNSC expectations for the performance of three functional areas comprising fourteen Safety and Control Areas (SCAs). This is known as the "licensing basis". Although there are design-related components in SCAs (Table 10-3), underlying these are the applicant or licensee's operating parameters, controls and safety culture that determine whether an organization can be a qualified nuclear licensee.

Table 10-3: CNSC Safety and Control Areas

Functional Area	Safety and Control Area
Management	Management System Human Performance Management Operating Performance
Facility and Equipment	Safety Analysis Physical Design Fitness for Service
Core Control Processes	Radiation Protection Conventional Health and Safety Environmental Protection Emergency Management and Fire Protection Waste Management Security Safeguards and Non-Proliferation Packaging and Transport

Other licensing matters of interest include the following:

- Reporting requirements, including the obligation of a licensee to file event or dangerous occurrence reports.
- Public information and disclosure program, which includes a protocol for public disclosure of facility events, developments, and/or activities.
- Indigenous engagement, including fulfilling the Duty to Consult and collaborating with Indigenous communities to properly protect, manage, consider, and reflect Indigenous Knowledge.
- Cost recovery, the CNSC is a fee-for-service agency charging $270/hour to cover all costs associated with regulatory duties including pre-licensing engagement, licence reviews, operational oversight, and inspections. A Services Agreement is required between licensees and the CNSC to secure their time.

10.2.1.1 Commission Hearings

Because of the unique nature of public hearings held by the Commission during licensing reviews, this section has been provided for additional context on licensing under the CNSC.

The Commission holds public hearings to consider and receive information necessary to make reasonable, fair, and transparent decisions regarding licence applications. Public hearings are governed by the CNSC Rules of Procedure and may be held as a one-part public hearing or a two-part public hearing, depending on the significance of the application.

At each hearing, a series of presentations, question and answer sessions, and statements are given to the Commission members who gather publicly at a location near the proposed activity, to review and discuss licence applications with the applicant and members of the public. In general, the applicant will present first, followed by the CNSC staff then intervenors who have applied in advance to address the Commission will be heard. It should be noted that intervenors are members of the public and/or organizations who have an interest or expertise in the subject of proceeding and have requested the opportunity to present information. Intervenors can provide positive or negative views of the proposed activities to be licensed however, the Commission does not include views touching on social acceptance in their decisions. Their sole interest is safety.

For licensing matters, the submission process for a hearing begins when a request for hearing is submitted to the Registry up to 12 months prior to the preferred hearing date. Upon review of the application, the CNSC will recommend which type of hearing will be most appropriate and notify the applicant along with deadlines for filing the Commission Member Documents (CMD) and presentation material. A CMD number is assigned to all documents associated with the matter of the given hearing and provided to the applicant as soon as assigned.

A notice of public hearing for both a one-part and two-part hearing is issued at least 60 days prior to the hearing. Submissions from intervenors are due 30 days before the appropriate hearing as per the deadline set by the commission.

One-part public hearings generally address less complex matters or those of limited public interest. A one-part public hearing may last more than one day. Planning typically begins upon receipt of the application by the Commission Registrar, up to 12 months before the hearing date. The general framework for one-part public hearings is presented in Table 10-4.

Table 10-4: One-Part Public Hearing Timeline

STEPS	TIMELINE
CNSC staff notify Registry	No later than 90 days before hearing and up to 12 months before hearing
Notice of public hearing issued	No later than 60 days before hearing
Applicant and CNSC staff file submissions	No later than 60 days before hearing
Intervenors submit requests to present and file relevant submission materials	No later than 30 days before hearing
Applicant and CNSC staff file supplementary material	No later than 7 days before hearing
Hearing	
Record of decision	Up to 60 days after hearing

Two-part public hearings address more significant licensing activities or when the level of public interest is high. This is the expected format for a new, proposed nuclear power generating facility in Alberta. A two-part public hearing can often last more than two days with separate hearings to be held at least 60 days apart. The applicant and CNSC staff are expected to attend both parts of a two-part Commission hearing. Planning typically begins upon receipt of the application by the Commission Registrar, up to 12 months before the hearing date.

Part One of a two-part public hearing involves submissions from the applicant then CNSC staff, followed by questions. During Part Two, the CNSC staff will present a brief overview of items addressed during Part One along with supplementary information that addresses questions from Part One. Intervenors who support or oppose the licensing activities are then invited to present submissions followed by questions. There is usually a question period following intervenor presentation and after considering written submissions. The general framework for two-part public hearings is presented in Table 10-5.

Table 10-5: Two-Part Public Hearing Timeline

Steps	Timeline
CNSC staff notify registry	No later than 90 days before hearing Part 1
Notice of public hearing issued	No later than 60 days before hearing Part 1
Applicant and CNSC staff file submissions	No later than 30 days before hearing Part 1
Applicant and CNSC staff file supplementary Material	No later than 7 days before hearing Part 1
Hearing Part 1	
Intervenors file requests to intervene and file submissions	No later than 30 days before hearing Part 2
Applicant and CNSC staff file supplementary material	No later than 7 days before hearing Part 2
Hearing Part 2	
Record of decision	Up to 60 days after hearing

There are times when confidential information, such as related to security or commercially sensitive material is not discussed in a public forum or made publicly available. Such information is heard in camera and is referred to as a “closed session”. A request for confidentiality must be submitted by the applicant to the Commission, taking into consideration the Commission’s Rules or Procedure, specifically Rule 12 which pertains to confidential documents before the commission. A request for confidentiality must include:

- An accompanying statement signed by a senior officer of the applicant indicating reasons for the confidentiality request.
- A confidential, un-redacted version marked “confidential” of the document containing all information for which the confidentiality is requested. This must identify all portions of the document for which confidentiality is claimed; and either:

- A non-confidential, redacted version of the document, or
- A non-confidential description or summary of the document if the request for confidentiality related to the entire document.

Public proceedings are webcast and available at no cost on the CNSC website for three months following the proceeding. In addition, transcripts of all public proceedings are made available on the CNSC website. Webcast recordings of older hearings can also be provided to any member of the public upon request.

10.2.2 Impact Assessment

In accordance with federal environmental legislation, an impact assessment is required for new nuclear facilities with a thermal output greater than 200 MWth. A Ministerial decision must be rendered before a licensing decision can be made by the Commission (however the reviews can be done in parallel), making the impact assessment a key first step to SMR deployment. This section provides an overview of the expected process for completing an SMR-focused impact assessment in Alberta, with the recognition that it is a novel undertaking having never been attempted before in the province and to be executed under new legislation untested by the emerging SMR nuclear industry.

According to the Government of Canada[95], an impact assessment is a "…planning and decision-making too used to assess the potential positive and negative effects of proposed projects." A broad range of factors would be included in an SMR impact assessment, including nuclear and non-nuclear aspects which are jointly evaluated by an Integrated Review Panel comprising the IAAC and the CSNC as the lifecycle regulator. The main goals of the assessment process are to foster sustainability, protect the environment and health, social and economic conditions from potentially adverse effects, while increasing positive effects and respecting the rights of the public and Indigenous peoples through meaningful consultation and the use of scientific and Indigenous knowledge. For additional information on the federal government's views on impact assessments, the reader is encouraged to consult the IAAC's online information.

In 2019, the federal government introduced its modernized *Impact Assessment Act* and in doing so, broadened the scope of the environmental assessments while simultaneously incorporating requirements under the NSCA and shifting the agency responsible for nuclear-sector EIAs from the CNSC to the IAAC. This revised approach has been referred to as the "Integrated Impact Assessment" and is described by the Canadian government as "…an assessment process led by a review panel in which the Participants will cooperate, to the extent possible, with the common objective that the requirements of the *Impact Assessment Act* and the NSCA are discharged as "one project, one assessment".

An undesirable outcome of the new Impact Assessment process is significantly long review timelines exceeding 5 years. Based on recent discussions within the nuclear sector, these

[95] *Impact Assessment Agency of Canada. 2023. Basics of Impact Assessments.* https://www.canada.ca/en/impact-assessment-agency/services/policy-guidance/basics-of-impact-assessments.html *Accessed April 14, 2023.*

untenable timelines are most likely due to three main factors: (1) the untested, interagency governance process, (2) the broader scope of the Act, including the introduction of lengthy pre-planning and "planning" phases and (3) the lack of deep nuclear-specific expertise of IAAC, which might not support a tailored view on impacts. For recent, non-nuclear industry projects completing impact assessments under the new Act (e.g., mining, new liquid natural gas plants, significant highways and infrastructure developments), the review timelines have indeed been extended from the previous federal review process- from 20% to as much as 45%[96].; this is understood to be resulting from the new governance process for single-agency reviews, and the broader scoping of the Act as evident in the now extensive Tailored Impact Specific Guidelines issued to proponents. For reference, these can be viewed online at the Agency's registry. Ministerial decisions for EIAs that previously required two to three years are now expected to take a minimum of three and up to five, or more, years.

This challenging regulatory environment is a focus for Canada's emerging SMR industry who are actively working with the federal government to identify solutions, as many SMRs under consideration are aiming for commercial operation by 2030 in compliance with Canada's commitments on climate change. This situation should be considered dynamic, and what is true today and so reported herein, could be different with shortened timeframes within the coming years. As such, the information presented in this section with regards to the expected timelines should be considered cautiously.

10.2.2.1 Review Phases

There are five phases comprising an impact assessment conducted under the federal Act. These are shown below (Figure 10-4) and outlined in Table 10-6. Prior to triggering the first phase, a proponent would have initiated internal studies, Indigenous and stakeholder engagements, and other activities needed to prepare for the planning phase well before the Impact Assessment process begins. For nuclear sector assessments, an Integrated Review Panel, consisting of representatives from the IAAC and the CNSC reviews a proponent's statement during the assessment phase and makes a recommendation to the Minister of ECCC on whether the project should proceed and if so, under which conditions. It is important to reiterate that this Act, its governance process, and the phases presented below remain largely untested in Canada. The CNSC is also expected to be reviewing the site licence application at this time and will be prepared to issue a decision within 30 days of the impact assessment decision. After the Ministerial impact assessment decision, the subsequent licensing processes and decisions are solely governed by the CNSC.

[96] Note that this is based on Hatch's review of projects completed under the old and new Acts, however it should be treated as a soft statistic as all projects reviewed by the Agency are unique. For additional information reviewing the IAA, the reader is directed to consult the following report: *Federal Impact Assessment Act Under Review, Measuring Progress on Projects & Timelines, Marla Orenstein, Canada West Foundation. May 2023*.

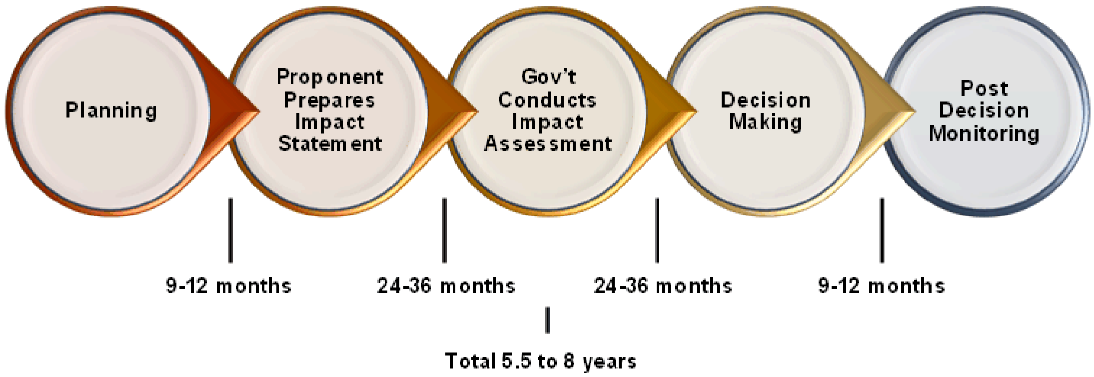


Figure 10-4: Impact Assessment Review Phases

Table 10-6: Details on the Impact Assessment Phases

PHASE	DESCRIPTION
Planning	Proponent submits Initial Project Description, kicking off the phase. Agency reviews for completeness, consults Indigenous communities and stakeholders and identifies issues; proponent incorporates comments and submits Detailed Project Description. Agency invites public and Indigenous peoples to provide information and contribute to planning the assessment. Agency accepts Detailed Project Description and issues Tailored Impact Statement Guidelines outlining requirements to be considered in preparing the statement. This concludes the phase.
Impact Statement	Proponent prepares a comprehensive report (the Impact Statement) outlining potential positive or negative impacts and controls or mitigations. Sound science and Indigenous knowledge inform the Impact Statement. The Agency continues consulting various Indigenous communities and stakeholders on the proposal. Submission and acceptance of the final Impact Statement concludes this phase.
Impact Assessment	A CNSC and IAA Integrated Review Panel reviews the Impact Statement report during this phase. This review considers potential environmental, health, social and economic impacts of proposed projects, including benefits. Potential impacts on Indigenous and treaty rights are also addressed. The panel uses information to develop an impact assessment report. No projects submitted under the IAA since [its ascension in] 2019, have successfully reached this phase. (Note: This does not include projects proposed for development on federal lands.)
Decision Making	Impact assessment report and Crown consultation outcomes informs the Ministerial decision on whether a project's adverse impacts once mitigations have been designed, remain acceptable and in the public interest. If yes, the Minister must establish conditions for the proponent. A decision statement is issued, setting out the rational for the decision, which provides transparency and accountability.
Post Decision	The Agency will be active in verifying compliance with the Decision Statement and correcting non-compliance. There will be greater transparency around follow-up programs with increased access to key documentation and opportunities for Indigenous and community participating in follow-up and monitoring programs.

An overview of the federal approvals combined with provincial requirements is shown in Section 11.5, as the regulatory roadmap.

10.3 Provincial Regulatory Approvals

The provincial regulatory framework for an SMR deployed at a SAGD facility in Alberta is not yet fully known but is expected to require a provincial environmental assessment review and other authorizations as presented in this section. Depending on the deployment scenario, for example, whether an SMR is designed for full integration with a SAGD facility, or whether an SMR is designed and constructed as an independent and separate component of a facility that also generates electricity and is connected to the provincial electricity grid, its main *Environmental Protection and Enhancement Act* (EPEA) approval will be administered by either the Alberta Energy Regulator (AER) due to the integration with a oil sands development, or the Alberta Utilities Commission (AUC) due to its utilization as a power generation development. Regardless of which regulator is tasked with EPEA review and approval, the opportunity for Alberta to identify and streamline its regulatory framework for the deployment of SMRs should be leveraged in the short-term to position the province as a predictable and promising new jurisdiction for nuclear power generation. This can assert the province as a model leader in understanding how to best regulate SMRs for use within new jurisdictions.

There are likely three key, provincial regulatory bodies responsible for the development of an SMR in association with a SAGD facility in Alberta. These bodies are listed below.

1. Alberta Energy Regulatory (AER):

   The AER is given authority under the *Responsible Energy Development Act*, and it regulates all oil, oil sands, natural gas, and coal development in Alberta from initial approval to decommissioning. If an SMR is expected to be solely associated with an oil sands development and not, for example, used to generate electricity for the province's grid, AER will likely have authority and approvals will be required.

2. Alberta Utilities Commission (AUC):

   The AUC governs all power generation for use in the province intended for commercial use. If an SMR co-located with a SAGD facility intends to produce power for distribution on the provincial electricity grid, the AUC may become involved. In Alberta, it is responsible for regulating power generation developments from initial approval to decommissioning. AUC is backed by the Alberta Utilities Commission Act. AESO is the body responsible for the Alberta grid. If the Project intends to sell power to the grid it will be necessary to gain approval for this activity.

3. Alberta Environment and Protected Areas (AEPA):

   AEPA (previously Alberta Environment and Parks) is a provincial ministry whose mandate is to protect and enhance Alberta's environment and ecosystems. The ministry is often represented by AER and/or AUC for industrial projects.

A provincial Environmental Impact Assessment (EIA) will be required to obtain EPEA approval. Much of the requirements for the provincial EIA overlap with those of the federal IA process. Similar to the cooperative relationship between the IAAC and the CNSC, provincial governments can work in collaboration with the federal IAAC to establish points of harmonization and reduce duplication of the overall regulatory scope. Early consultation with regulatory agencies, both federal and provincial, will help to ensure this process runs efficiently.

As there are provincial requirements for an EIA, as well as a federal IA, it is assumed that a joint review will be conducted with both provincial and federal agencies. The collaborative review panel would allow the agencies to share knowledge and subject matter experts for their own reviews. An interagency agreement between the responsible Alberta EIA administrator, and the CNSC and IAA could be considered for reducing the regulatory burden of SMR development in Alberta.

Figure 10-5 visualizes the steps in the environmental assessment process for Alberta, and what triggers and Environmental Impact Assessment (EIA). The process follows a similar governance process as the federal review.

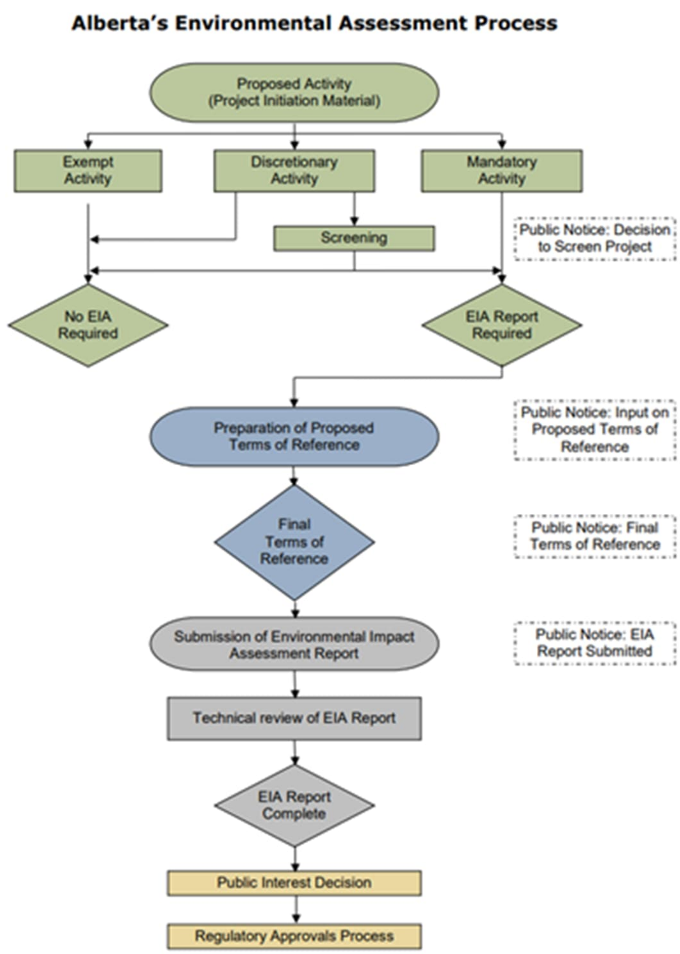


Figure 10-5: Alberta's Environmental Assessment Process

10.3.1 *Licences, Approvals, and Permits*

Table 10-7, below, outlines the expected provincial approvals needed for an SMR associated with a SAGD facility in the province of Alberta. As discussed in previous sections there is uncertainty around the regulatory pathways for these types of projects, and this list may change in the future. Some of these approvals are probable based on the information available at this time, they may become required depending on siting and design. It should be noted that municipal or regional requirements that includes several subregional land use plans, will also be important in the regulatory landscape for SMRs to be deployed in Alberta.

Table 10-7: Provincial Permits, Approvals, Licenses and Guiding Legislation for SMR Developments in Association with SAGD Facilities

Required, Potential, or Guiding	Governing Legislation	Licence, Approval, or Permit	Delegated Authority	Purpose
Required	*Environmental Protection and Enhancement Act*	Environmental Impact Assessment (EIA)	Alberta Energy Regulator / Alberta Utilities Commission / Alberta Environment and Protected Areas (AER) / (AUC) / (AEPA)	An Environmental Impact Assessment (EIA) is required under the Environmental Assessment Regulation when a project falls under the Mandatory Activities outlined in the Mandatory and Exempted Activities Regulation. The Project is defined within the Mandatory and Exempted Activities Regulation under Schedule 1(k) a thermal electrical power generating plant that uses non-gaseous fuel and has a capacity of 100 megawatts or greater. Therefore, the Project will require an EIA as it meets the mandatory activities specification for power capacity. Under the EPEA, a comprehensive EIA is required to assess the potential environmental and socio-economic impacts of the project and identify measures to mitigate these impacts.
	Environmental Protection and Enhancement Act	Approval	Alberta Energy Regulator / Alberta Utilities Commission / Alberta Environment and Protected Areas (AER) / (AUC) / (AEPA)	Activities specified in the Activities Designation Regulation under the EPEA Act for industrial or energy projects require an approval prior to their construction or operation. The Act outlines the application procedure necessary to apply for an approval with further detail provided in the Approvals and Registrations Procedure Regulation. The Regulation outlines the information and content that is required in an application to inform the decision whether to grant an approval.
	Oil Sands Conservation Act	Approval	Alberta Energy Regulator (AER)	The Act is administered by AER for the development of oil sands resources and related facilities in Alberta. SAGD sites and their associated facilities are governed by this act and as such the Project may require an approval under this act.

Required, Potential, or Guiding	Governing Legislation	Licence, Approval, or Permit	Delegated Authority	Purpose
	Oil and Gas Conservation Act	Approval	Alberta Energy Regulator (AER)	The Act is administered by AER and regulates development of oil and gas resources and related facilities in Alberta. Facility is defined under the act as “any building, structure, installation, equipment or appurtenance over which the Regulator has jurisdiction and that is connected to or associated with the recovery, development, production, handling, processing, treatment or disposal of hydrocarbon-based resources, including synthetic coal gas and synthetic coal liquid, or any associated substances or wastes or the disposal of captured carbon dioxide”. As this project may be related directly to an oil sands facility, an OGCA approval may be required.
	Hydro and Electric Energy Act	Approval	Alberta Utilities Commission (AUC)	Approval is required for power development not intended for personal use. The act also outlines the requirements for approval by the AUC for construction and operation of power generation as well as distribution. If power is to be sold to the grid the project may require approvals from AUC and AESO.
	Water Act	Licence	Alberta Energy Regulator (AER)	The Water Act regulates the use of water resources in the province, including for cooling and other purposes at power plants. The project would require approvals under the Water Act for the use of water resources, as well as for any discharge of wastewater or other effluent from the facility.
	Historical Resources Act	Approval	Historical Resources Management Branch (HRMB)	Industrial facilities are required to submit an HRA prior to the onset of activities, whether there is listed areas of Historic Resource Value at the site or not. The purpose of the HRA is for the HRMB to determine if there are any Historical Resources of Value (HRVs) at a site. If the HRMB determines that the site has the potential for HRVs, they may require a Historical Resources Impact Assessment (HRIA) to be completed prior to issuing an approval.
	Directive 056: Energy Application and Schedule	Licence	Alberta Energy Regulator (AER)	Directive 056 outlines requirements for a licence application to construct and operate a facility associated with oil and gas. If the project is regulated by AER, it will require a D056 licence.
	Directive 071: Emergency Preparedness	Approval	Alberta Energy Regulator (AER)	Directive 071 outlines the requirements for the planning and contents of the emergency response plans applicable to

Required, Potential, or Guiding	Governing Legislation	Licence, Approval, or Permit	Delegated Authority	Purpose
	and Response Requirement for the Petroleum Industry			resource developments. Directive 071 also outlines the steps to take for preparation and response to an incident. If the project is regulated by the AER, the existing emergency response plan for the facility can be amended to include the SMR.
	Wildlife Act	Wildlife Research Permit and Collection Licence	Alberta Environment and Protected Areas (AEPA)	Any person, agency, or institution whose work involves wildlife research or collection in Alberta needs a Wildlife Research Permit and Collection Licence.
Potential	*Pipeline Act*	Approval	Alberta Energy Regulator (AER)	Under Section 2(a) of the Pipeline Act, any pipeline situated wholly within the property of a processing plant must be covered by the facilities approvals and is not covered by the Pipeline Act. For any pipelines not wholly situated within the property of a processing plant, AER must approve the construction of a pipeline pursuant to this act, and also must grant a licence to operate only after the pipeline has been tested as per the rules or is otherwise approved by the regulator.
	Public Lands Act	Approval	Alberta Energy Regulator / Alberta Utilities Commission / Alberta Environment and Protected Areas (AER) / (AUC) / (AEPA)	The Public Lands Act governs the use of public lands in Alberta and would require approvals for any use of public land for the nuclear power plant or associated infrastructure. As the SMR is planned to be sited near the existing SAGD facility, within the existing surface lease, additional approval may not be required.
	Fisheries (Alberta) Act	Fish Research Licence	Alberta Environment and Protected Areas (AEPA)	Licence required where fish are being collected as part of a fish rescue operation (sometimes referred to as a fish salvage) with the purpose of avoiding fish mortality due to a natural event or authorized activity (example de-watering of a site for construction activities).
Guiding	*Fisheries (Alberta) Act*		Alberta Environment and Protected Areas (AEPA)	Prevention of harm to fisheries resources in Alberta.
	Wildlife Act		Alberta Environment and Protected Areas (AEPA)	Prevention of harm to wildlife populations in Alberta.
	Alberta Land Stewardship Act		Alberta Environment and Protected Areas (AEPA)	Enables the current and future land-use objectives of the province.

10.4 Provincial Regulatory Framework Review and Comparison

This section provides an overview of the current nuclear regulatory framework and experience in Canada. While nuclear energy is federally regulated, several provinces have nuclear experience and/or have taken steps to establish nuclear power plants.

Given Alberta's inexperience in the nuclear market, it may look to adopt precedence and policy tools set by other provinces including Ontario and New Brunswick. However, if the SMR is used to generate electricity for sale or distribution to the provincial electricity grid, then an understanding of how the electricity market in Alberta functions differently to many other provinces is required. Within the province of Alberta, electricity generation and industrial facilities exist within a competitive market and therefore many policy tools listed for other provinces would not be applicable to Alberta standards. Therefore, an initial focus should be to establish policy and provide clarity on regulatory frameworks by engaging with other provinces with experience in nuclear development such Ontario and New Brunswick. To that extent, a brief comparison is presented in Table 10-8 to identify policy and experience differences in Alberta compared to Ontario and New Brunswick, the only two provinces with currently operating nuclear power plants.

Table 10-8: Regulatory Framework Review for Alberta, New Brunswick, and Ontario

	ALBERTA	NEW BRUNSWICK	ONTARIO
	NUCLEAR POWER OPERATING EXPERIENCE		
Years of Experience	0	40	75
Current Nuclear Operations	None	Point Lepreau Nuclear Generating Station (705 MW)	Darlington Nuclear Generating Station (3512 MW), Bruce A and B Nuclear Generating Stations (6232 MW), Pickering Nuclear Generation Station (3100 MW)
Current Class IA facility licensees	None	New Brunswick Power	Ontario Power Generation, Bruce Power
Nuclear Operation Deployment			
Environmental/Impact Assessments	Environmental Assessment Regulation, Environmental Protection and Enhancement Act, 2000	Environmental Impact Assessment Regulation, Clean Environment Act, 1973	Environmental Assessment Act, 1990

	Alberta	New Brunswick	Ontario
Federal and Provincial Arrangements	None	MOU between the CNSC and the New Brunswick Emergency Measures Organization (2012)	MOU between the CNSC and the Ontario Ministry of Labour (2017), MOU between the CNSC and the Fire Marshal and Emergency Management (2015)
Interprovincial Agreements	Interprovincial SMR MOU	Interprovincial SMR MOU	Interprovincial SMR MOU
Financing	Private investors and investments	Crown corporations and power companies	Crown corporations and power companies, private partnerships
Nuclear Waste Management Responsibility	NWMO will accept used SMR fuel at a future date	New Brunswick Power NWMO	Ontario Power Generation NWMO
Emergency Preparedness for nuclear (in addition to federal nuclear preparedness procedures)	None	MOU between the CNSC and the New Brunswick Emergency Measures Organization (2012)	MOU between the CNSC and the Fire Marshal and Emergency Management (2015)
Provincial Electricity/Energy Generation			
Provincial Electricity/Energy Regulatory Agencies	Alberta Utilities Commission (AUC), Alberta Energy Regulator (AER), Alberta Energy	New Brunswick Power, New Brunswick Energy and Utilities Board (EUB)	Ontario Power Generation
Regulatory Framework	Hydro and Electric Energy Act, 2000	New Brunswick Electricity Act, 2013 New Brunswick System Operator Requirements	Electricity Act, 1998 Ontario Clean Energy Benefit Act, 2010

Given Ontario and New Brunswick's existing experience with nuclear power, the key difference between the two provinces and Alberta is Alberta's inexperience with nuclear energy projects. As such, Alberta currently lacks a nuclear-specific policy and regulatory framework to allow SMRs to become a clean energy resource within the province. However, the signing of the Interprovincial SMR MOU suggests that the province is open to working with private companies on potential nuclear projects.

Additionally, while Alberta lacks a nuclear-specific regulatory framework, the province has a well-developed environmental regulatory framework for power plants that can be used to inform the regulatory pathway for potential nuclear power projects. In addition, it's robust emergency management framework could be modified to address nuclear-sector needs.

11. Other Regulatory Discussions

11.1 Vendor Design Review

The CNSC also offers a Pre-Licensing Vendor Design Review (VDR)[97] which is an optional service provided by the CNSC upon request by and for a vendor or designer of a reactor facility. The VDR operates as a feedback mechanism that will enable CNSC feedback to be provided early in the design process based on the vendor's reactor technology. The objective of a VDR is to verify at a high level the acceptability of a nuclear power plant design with respect to CNSC requirements and expectations, as well as Canadian codes and standards. A VDR is carried out within a service agreement and takes place in three phases. Engaging in the VDR process is not an application for any licence and does not certify nor involve the issuance of a licence and is thus not applicable for proponents. However, it can function to assist the CNSC in understanding the design of the proposed reactor facility during the licensing process. In addition, conclusions of a VDR are not binding and influencing of decisions made by the Commission. However, the VDR process will allow for fundamental barriers to be identified early and is encouraged as this process may result in a more efficient licensing process. In addition, the CNSC implements a focused approach to accepting VDR applications and has prioritized activities to prepare for potential SMR licence applications.

11.2 Facility and Regulatory Integration

11.2.1 Nuclear Siting Conditions

The CNSC requirements for site evaluation and site preparation are described in REGDOC-1.1.1. The CNSC's approach utilizes a commensurate risk graded approach to particular characteristics of the facility or activity. A site evaluation is an integral piece for nuclear licensing and must be completed and accepted by the CNSC prior to issuance of any licence. In addition, the site evaluation is a primary contribution to the EA conducted in accordance with federal environmental assessment legislation. The primary objectives of the site evaluation are:

- To produce a safety case for the site preparation phase of the project, to be integrated into the licensing basis for site preparation activities.
- To document conditions of the site and surrounding region to be addressed for the proposed technology and associated safety control measures.
- To demonstrate that proposed nuclear technologies for the site will withstand the conditions of the proposed site and its surroundings; and
- To demonstrate site suitability for the full lifecycle of the nuclear project.

A nuclear site evaluation should consider site characteristics as well as the effects of external events depending on probability and severity. In general, the site evaluation should demonstrate that adverse environmental, social, and cultural impacts associated with the full

[97] https://nuclearsafety.gc.ca/eng/reactors/power-plants/pre-licensing-vendor-design-review/index.cfm.

life cycle of the facility are acceptable to regulatory bodies and that site characteristics do not compromise safety goals of the facility. These considerations are to be reviewing throughout the IA process and various phases of CNSC licensing. An overview of general siting considerations to consider for an SMR are:

- Site condition.
- Surrounding land use: proximity to anthropological hazards, residential properties, commercial facilities, existing industrial facilities, or agricultural land use.
- Utilities: access to utility needs such as power, sewage, and water. Utility requirements and impacts to existing infrastructure should be considered.
- Natural environment and biodiversity: presence of listed SAR, migratory birds, proximity to and presence of functional wildlife corridors, significant vegetation communities, watercourses, and wetlands; and
- Indigenous communities: proximity to lands and resources used for traditional purposes, proximity to reserve lands.

Siting conditions and site evaluations is covered in further depth in Section 3.

11.2.2 Exclusion Zones

The exclusion zone is an area surrounding a nuclear facility where no permanent dwelling or human activity may take place. In Canada, the exclusion zone for existing large CANDU nuclear power plants is typically an area of 1 km surrounding the plant; however, this is expected to be significantly smaller for SMRs. Many vendors believe a 200 m exclusion zone is acceptable for their design; this assumption has not been tested or reviewed by the CNSC.

The exclusion zone is determined by multiple factors. Characterization of the exclusion zone relies heavily on design information including descriptions of major SSCs, dose limits, security considerations, environmental conditions and emergency preparedness considerations that are affected by the land use around the site. SMR developers are proposing a zero-exclusion zone concept which is currently being tested in the ongoing licensing efforts, however a regulatory decision has yet to be made.

11.3 Emergency Preparedness and Response

11.3.1 Division of Responsibilities

A nuclear facility operator must be able to respond to any emergency incident that cannot be practically eliminated to prevent escalation of the incident, mitigate consequences, and achieve a long-term safe stable state following the incident. However, an effective emergency response requires not only effective accident management measures, but also sufficient emergency preparedness.

In Canada, at the federal level, the government is responsible for regulating the use of nuclear energy, managing nuclear liability, and supporting the responses of provincial governments to nuclear emergencies. Thus, in accordance with both subsection 24(4) of the

NSCA and paragraphs 5 to 7 of the *Class I Nuclear Facilities Regulations*, the CNSC requires applicants to outline its emergency preparedness and response policies, programs, and procedures for the proposed facility. Specifically, the Licence to Construct, Licence to Operate, and Licence to Decommission applications must include the information regarding emergency preparedness found in Table 11-1.

Table 11-1: CNSC Emergency Planning Requirements

Licence to Construct	The measures proposed to control the release of nuclear and/or hazardous substances into the environment, including: • A description of the preparations made to ensure that any emergencies that may arise at the facility during its lifetime are dealt with safely and effectively. • Details of emergency preparedness policies, programs, and procedures. • A schedule for the provision of detailed information concerning emergency preparedness during operation and decommission.
Licence to Operate	The measures proposed to prevent or mitigate the effects of accidental releases of nuclear and/or hazardous substances on the environment, the health and safety of persons, and the maintenance of national security, including: • Assisting off-site authorities in planning and preparing to limit the effects of an accidental release. • Notifying off-site authorities of an accidental release or the imminence of an accidental release. • Assisting off-site authorities in dealing with the effects of an accidental release. • Reporting during and after an accidental release; and • Testing the implementation of the measures to prevent or mitigate the effects of an accidental release.
Licence to Decommission	The measures proposed to prevent or mitigate the effects of accidental releases of nuclear and/or hazardous substances on the environment, the health and safety of persons, and the maintenance of national security, including an emergency response plan.

However, emergency management is not the sole responsibility of the CNSC, but is divided amongst the licensee and provincial authorities as indicated in Table 11-2:

Table 11-2: Emergency Management Responsibilities

ORGANIZATION	RESPONSIBILITIES
Nuclear power plant licensee	Prevention of nuclear emergencies. Stops or mitigates the progression of the nuclear emergency. Minimizes the impacts on the surrounding communities; and Provides clear, up-to-date information and technical support to provincial and local authorities to help them in their response.
CNSC	Oversees the operator's response. Provides technical advice to federal and provincial response authorities. Ensures that the appropriate response actions are taken by the operator; and Informs the government and public of its assessment of the situation.
Provincial authorities (i.e., provincial governments, municipal governments, emergency responders)	Government bears primary responsibility for protecting public health and safety, property, and environment. Initiates public alerting systems. Decides and communicates the protective measures for the public (i.e., evacuate, shelter, take potassium iodide pills). Monitors radiation levels outside of the facility; and Establishes evacuation centres.

11.3.2 Emergency Preparedness

All levels of government, as well as various agencies and organizations, bear the responsibility of developing and implementing emergency plans to address nuclear emergencies outside of the boundaries of CNSC-licensed nuclear facilities. This includes the federal *Emergency Management Act (2007)*, and the Federal Nuclear Emergency Plan. However, the licensee remains responsible for the prevention of nuclear emergencies within the facility. The CNSC, other Canadian governmental authorities, and the International Atomic Energy Agency (IAEA) all provide guidance to applicants in this regard.

11.3.2.1 CNSC Guidance for Applicants and Licensees

As indicated in Table 11-2 licence applicants and licensees must design and implement an emergency preparedness program (EP program) when preparing the Licence to Construct. An effective EP program is essential for ensuring that the proper measures are in place to ensure a timely, coordinated, and effective response to any emergency. EP programs must include four components: planning basis, emergency response plan and procedures, preparedness, and program management (CNSC REGDOC 2.10.1):

- *"Planning basis: An analysis of risks and hazards the EP program will address. Must nuclear events and the release of hazardous materials.*
- *Emergency plan and procedures: A comprehensive description of how a response will be executed, with accompanying support material.*

- *Preparedness: The processes to ensure that people, equipment, and infrastructure will be ready to execute a response according to the emergency response plan and procedures.*
- *Program management: The management system aspects that assure the effectiveness of the EP program."*

The CNSC provides further guidance for licence applicants and licensees to fulfill their responsibilities in the event of a nuclear emergency through their regulatory documents. Key regulatory documents include:

11.3.2.2 REGDOC-2.10.1 Nuclear Emergency Preparedness and Response (Version 2) (2016)

This document pertains to the components and elements CNSC licence applicants and licensees shall implement and consider when establishing an EP program. It refers primarily to nuclear events and indicates how licensees should test the implementation measures of their EP programs.

11.3.2.3 REGDOC-2.3.2 Accident Management (Version 2) (2015)

This document defines the requirements and guidance of the CNSC for licence applicants and licensees to develop, implement, and validate an integrated accident management approach for reactor facilities. The approach includes necessary items such as emergency operating procedures and severe accident management guidelines and must demonstrate an applicant or licensee's ability to manage anticipated operational occurrences, design-basis accidents, and beyond-design-basis accidents.

11.3.2.3.1 Other Canadian Governmental Guidance for Applicants and Licensees

11.3.2.3.2 General Nuclear Safety and Control Regulations (Nuclear Safety and Control Act, SOR/2000-202)

Under section 12 of this regulation, licensees are obligated to take all reasonable precautions to maintain security of nuclear facilities and nuclear substances, the health and safety of persons, to protect the environment, and to control the release of radioactive nuclear substances or hazardous substances.

11.3.2.3.3 Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry

Directive 071 outlines the emergency preparedness and response requirements for the petroleum industry in Alberta, including the development of emergency response plans, training, and exercises, and reporting and documentation of incidents.

11.3.2.4 International (IAEA) Guidance

While the CNSC has incorporated many of the IAEA safety standards into their regulatory documents, the documents listed in this section may provide some additional guidance for facility operators in preparing an effective emergency management program.

11.3.2.4.1 Preparedness and Response for a Nuclear or Radiological Emergency (IAEA Safety Standards Series GS-R-2, 2002, Revised in 2015)

This document may provide some additional guidance on the adequate level of preparedness and response required for a nuclear or radiological emergency, and for mitigating the consequences if an emergency arises.

11.3.2.4.2 Arrangements for Preparedness for a Nuclear or Radiological Emergency (IAEA Safety Standards Series GS-G-2.1, 2007)

This document may provide some additional guidance on the appropriate responses for a variety of emergencies and to provide further guidance on general, functional, infrastructure, and operational requirements for nuclear facilities.

11.3.2.4.3 Preparation, Conduct and Evaluation of Exercises to Test Preparedness for a Nuclear or Radiological Emergency (IAEA EPR-Exercise, 2005)

This is a training course provided by the IAEA on the preparation, conduction, and evaluation of exercises to test preparedness for a nuclear or radiological emergency, including information on concepts, terminology, preparation and practical processes for conduction and evaluation, and example scenarios for practice.

11.3.2.4.4 Fundamental Safety Principles (IAEA Safety Standards Series No. SF-1, 2006)

This document establishes fundamental safety objectives, principles, and concepts that provide the bases for the IAEA's safety standards.

11.3.3 Emergency Response (Accident Management)

The CNSC and IAEA emphasize the importance of emergency preparedness for an effective emergency response, and that measures should be taken to the extent possible to eliminate opportunities for emergencies. However, in the event an emergency occurs despite best efforts, an effective emergency response is required.

Emergency response refers to both actions taken on-site and off-site of the nuclear facility to prevent escalation of the emergency incident, mitigate consequences on health, safety, and the environment, and achieve a long-term safe stable state following the incident. According to CNSC REGDOC 2.10.1 (see Section 1.8.2.1), the practical goals of an emergency response are to:

- *"Regain control of the situation.*
- *Prevent or mitigate consequences at the scene.*
- *Prevent the occurrence of deterministic health effects in workers and the public.*
- *Prevent, to the extent practicable, the occurrence of stochastic health effects in the population.*
- *Prevent, to the extent practicable, the occurrence of non-radiological effects in individuals and among the population.*
- *Render first aid and to manage the treatment of radiation injuries.*

- *Protect, to the extent practicable, property and the environment; [and]*
- *Prepare, to the extent practicable, for the resumption of normal social and economic activity."*

An operator for a nuclear facility must have measures in place for an effective on-site emergency response, while governmental and provincial authorities are responsible for off-site emergency responses as discussed in Section 11.3.3.1.

11.3.3.1 Reference Documents for Off-site Emergency Response Efforts

In addition to the guidance documents discussed in Section 11.3.3.1, there are several publicly available documents that are used in creation of the CNSC regulatory documents and governmental or agency emergency response efforts. While these do not necessarily apply to an applicant or licensee, some key documents are summarized below for reference purposes.

11.3.3.1.1 Federal Emergency Response Plan (Government of Canada, 2011)

This "all-hazards" plan is curated to harmonize federal, provincial/territorial, non-governmental, and private emergency response efforts. It is applicable to domestic emergencies (or international emergencies with a domestic impact) and applies to all federal government institutions.

11.3.3.1.2 Federal Nuclear Emergency Plan (5th Edition) (Health Canada, 2014)

This plan and its annexes describe the Canadian government's preparedness and response framework for coordinating the federal off-site response to significant nuclear emergencies, including coordinating scientific and technical resources. This applies to both the delivery of the federal government in its responsibilities and in its support of provincial/territorial actions.

11.3.3.1.3 Generic Criteria and Operational Intervention Levels for Nuclear Emergency Planning and Response (Health Canada, 2018)

This document is intended to assist federal and provincial emergency response authorities in determining appropriate protection measures for public health. It provides recommendations on "—dosimetric and operational quantities, in terms of generic criteria and Operational Intervention Levels (OIL), to assist emergency response authorities when developing protection strategies for nuclear emergencies."

11.3.3.1.4 Canadian Guidelines for the Restriction of Radioactively Contaminated Food and Water Following a Nuclear Emergency (Health Canada, 2000)

This document is intended to assist federal and provincial emergency response authorities in determining appropriate protection measures for public health. It describes Health Canada's guidelines and rationale for the control of radioactively contaminated foods and public drinking water following a domestic or international nuclear emergency.

11.3.3.1.5 Accident Management Programmes for Nuclear Power Plants (IAEA Safety Standards Series No. SSG-54, 2019)

An older version of this document has been incorporated by the CNSC into their regulatory documents. It may provide additional guidance on the development and implementation of accident management programs (AMPs) established in the IAEA Safety Standards series.

11.3.3.1.6 Implementation of Accident Management Programmes in Nuclear Power Plants (IAEA Safety Reports Series No. 32, 2004)

This document may provide some additional guidance on the individual elements that must be addressed by the team responsible for developing and implementing a facility-specific AMP at a nuclear power plant.

11.3.3.1.7 Guidelines for the Review of Accident Management Programmes in Nuclear Power Plants (IAEA Services Series No. 9, IAEA-SVS-09, 2003)

This document may provide some additional guidance on how to assess the status of various phases of AMP implementation, to provide licensees with suggestions for improvement, and to give opportunities for licensees to explore personnel principles and possible approaches for the effective implementation of an AMP.

11.4 Risk Management Framework

11.4.1 Environmental Risk Assessment

A nuclear licensee is required to prepare an environmental risk assessment (ERA) report which encompasses the results of a human health risk assessment and an ecological risk assessment. The suggested guidelines for an ERA are provided by the CSA group guide for Environmental Risk Assessments at Class I Nuclear Facilities and Uranium Mines and Mills (N288.6-12), however requirements may vary depending on applicable regulations, licences, and permits. The technical framework of an ERA should include components within the context of human health and ecological risk assessment encompass:

- Problem formulation
- Exposure assessment
- Toxicity/effects assessment; and
- Risk characterization.

In addition, the ERA must summarize key finding of the human health and ecological risk assessment and provide recommendations for the monitoring program and risk management.

11.4.2 Seismic Hazards

In Canada, the CNSC defines requirements and supplies guidance for licence applicants for water-cooled nuclear power plants. Under the CNSC, seismic qualification for all structures, systems, and components (SSCs) must meet Canadian national (or equivalent) standards. Requirements for seismic design include:

- Instrumentation for monitoring seismic activity onsite.

- Technical safety objectives and corresponding load categories.
- Seismic input motion.
- Seismic analysis, design, and testing of instrumentation, equipment, and structural systems; and
- Structural layout criteria (following best engineering practices).

The IAEA also provides guidance for the safe seismic design of nuclear facilities in its Safety Standards Series No. SSG-67 Seismic Design for Nuclear Installations document, which provides recommendations for meeting safety requirements for the design and lifetime of nuclear facilities. Additionally, the IAEA's Safety Standards Series No. SSR-1 Site Evaluation for Nuclear Installations stipulate that any foreseeable internal or external seismic hazards associated with a nuclear site must be evaluated and incorporated as an input to the plant's seismic design.

11.5 Regulatory Summary: Road Map and Permit Matrix

11.5.1 Regulatory Roadmap

The regulatory roadmap presented in this section reflects the key regulatory opportunities influencing the preparation, construction, operation, and decommission of an SMR facility in Alberta. As these requirements are intended to support planning and reduce the overall level of adverse impacts related to developments, regulatory opportunities can be viewed as a pathway for planning an environmentally sustainable and locally acceptable facility. Timelines for completing the series of requirements can vary greatly depending on the maturity of the project's design and the ability of the proponent to adequately address questions that might not be well defined in the early phase of a facility. Despite this, it is important that proponents fully understand how they will be mitigating potential impacts and that these can be communicated to Indigenous and local communities and project stakeholders in a meaningful way. The timelines in Figure 11-1 reflect a wholistic understanding of the complex and interconnected federal, provincial, and municipal regulatory process for licensing a new nuclear power facility in Canada. Additionally, as federal environmental legislation has recently undergone notable reforms (e.g., Bill C-69), this figure reflects the impact of these reforms on anticipated regulatory timelines.

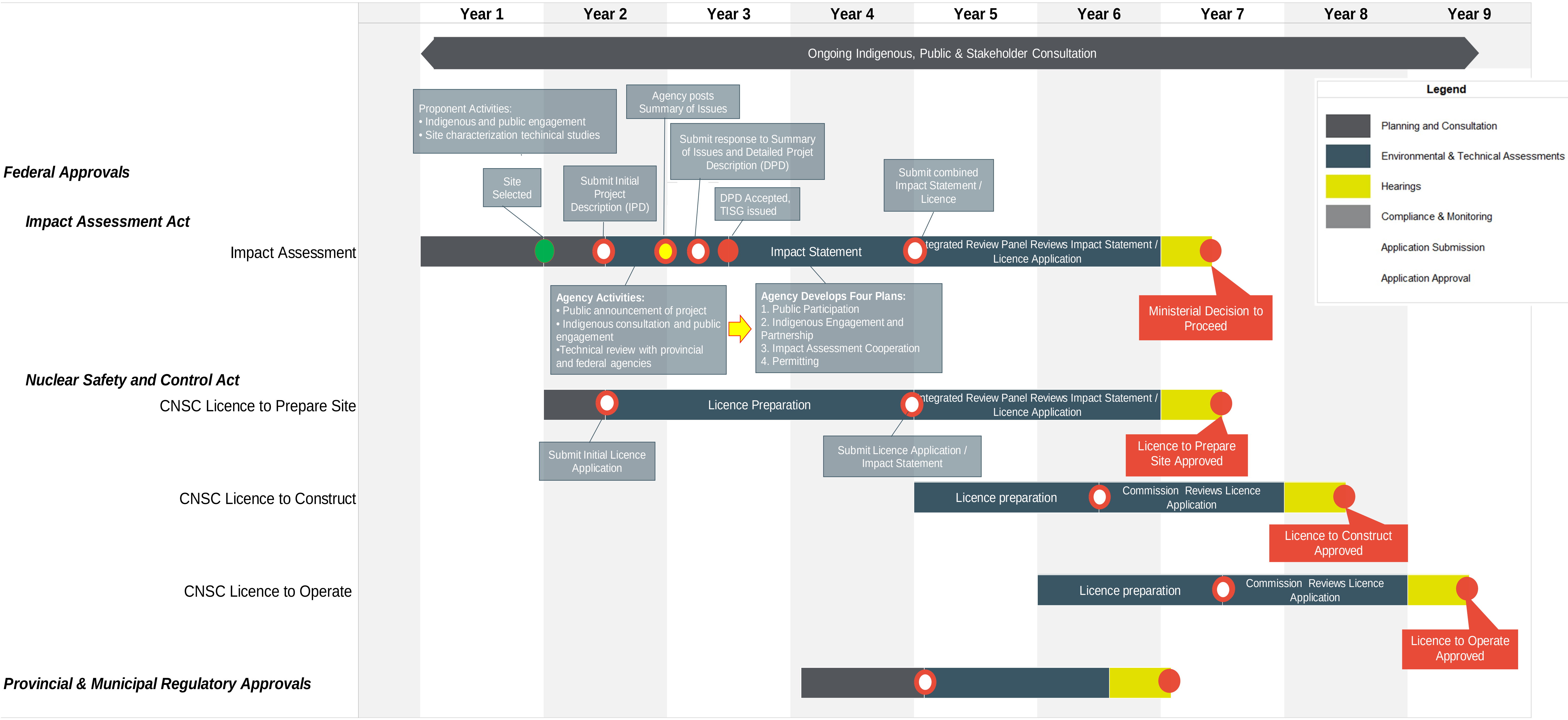


Figure 11-1: Regulatory Timeline

11.5.2 Permit Matrix

The Permit Matrix presented in Table 11-3 provides a roadmap of anticipated and required licences, approvals, and permits required to operate an SMR facility in Alberta, with a focus on the main approvals. Further approvals may be identified through discussions with federal, provincial, and municipal regulators.

Table 11-3: Permits, Approvals, and Licences Matrix

Legislation/ Regulation	Type of Approval	Description	Level of Government	Jurisdiction	Timeline	Applicability
		Nuclear				
Nuclear Safety and Control Act, Class I Nuclear Facilities Regulations	Licence to Prepare Site	Required for a licensee to demonstrate their ability to manage a nuclear facility and to begin preparations of the site outside of the nuclear-critical components	Federal	Canadian Nuclear Safety Commission	4 years	Required
	Licence to Construct	Required for a licensee to construct nuclear related components of the facility	Federal	Canadian Nuclear Safety Commission	3.5 years	Required
	Licence to Operate Site	Required for a licensee to complete final commissioning activities and to operate the facility	Federal	Canadian Nuclear Safety Commission	3.5 years	Required
	Licence to Decommission	Required for a licensee to carry out decommissioning activities. This process includes phased removal of regulatory controls from the licensed facility.	Federal	Canadian Nuclear Safety Commission	2 years	Required
		Non-Nuclear				
Impact Assessment Act	Impact Assessment	Required to assess the environment, health, social, and economic impacts of the proposed project.	Federal	Impact Assessment Agency of Canada	5-7 years	Required
Fisheries Act	Fisheries Act Authorization (FAA)	Fish habitat offsetting activities.	Federal	Fisheries and Oceans Canada (DFO)	1 year	Potential
Species at Risk Act	Authorization	Authorization of activities affecting a listed wildlife species (other than fish), any part of its critical habitat or the residences of its individuals.	Federal	Environment and Climate Change Canada (ECCC)	1 year	Potential

Legislation/ Regulation	Type of Approval	Description	Level of Government	Jurisdiction	Timeline	Applicability
Directive 056: Energy Development Applications and Schedule Approval	Approval	Directive 056 outlines requirements for a licence application to construct and operate a facility associated with oil and gas.	Provincial	Alberta Energy Regulator (AER)	1 year	Required / Anticipated
Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry	Approval	Directive 071 outlines the requirements for the planning and contents of the emergency response plans applicable to resource developments. Directive 071 also outlines the steps to take for preparation and response to an incident.	Provincial	Alberta Energy Regulator (AER)	1 year	Required / Anticipated
Environmental Protection and Enhancement Act	Impact Assessment	An Environmental Impact Assessment (EIA) is required when a project falls under the *Mandatory and Exempted Activities Regulations* under EPEA.	Provincial	Alberta Environment and Parks (AEPA)	2 years	Required
Environmental Protection and Enhancement Act	EPEA Approval	Approval required under EPEA for activities that fall under the *Activities Designation Regulation*, including construction, operation, decommissioning and reclamation.	Provincial	Alberta Energy Regulator (AER) or Alberta Environment and Parks (AEPA)	1 year	Required
Fisheries (Alberta) Act	Fish Research Licence	Licence required where fish are being collected as part of a fish rescue operation with the purpose of avoiding fish mortality due to a natural event or authorized activity.	Provincial	Alberta Environment and Protected Area (AEPA)	6 months	Potential
Historical Resources Act	Historic Resources Application	Industrial facilities are required to submit an HRA prior to the onset of activities, whether there is listed areas of Historic Resource Value at the site or not.	Provincial	Historical Resources Management Branch (HRMB)	6 months	Required
Hydro and Electric Energy Act	Power Plant Approval	Approval is required for power development not intended for personal use.	Provincial	Alberta Utilities Commission (AUC)	1 year	Required

Legislation/ Regulation	Type of Approval	Description	Level of Government	Jurisdiction	Timeline	Applicability
Oil and Gas Conservation Act	Facility Licence/Approval	The act regulates development of oil and gas resources and related facilities in Alberta.	Provincial	Alberta Energy Regulator (AER)	1 year	Required
Oil Sands Conservation Act	Facility Licence/Approval	The act regulates the development of oil sands resources and related facilities in Alberta	Provincial	Alberta Energy Regulator (AER)	1 year	Required
Pipeline Act	Licence to Construct and Operate	If any pipeline built is not wholly situated within the battery limits the site, it will require approval.	Provincial	Alberta Energy Regulator (AER)	6 months	Potential
Public Lands Act	Approval	The Public Lands Act governs the use of public lands in Alberta and would require approvals for any use of public land for the nuclear power plant or associated infrastructure.	Provincial	Alberta Energy Regulator (AER)	6 months	Potential
Water Act	Water Act Licence	The Water Act regulates the use of water resources in the province, including for cooling, diversion, and any other purposes at power plants.	Provincial	Alberta Energy Regulator (AER)	6 months	Required / Anticipated
Wildlife Act	Wildlife Research Permit and Collection Licence	Any person, agency, or institution whose work involves wildlife research or collection in Alberta	Provincial	Alberta Environment and Protected Area (AEPA)	6 months	Required
Municipal Authority	Development Permit	A development permit is required for any development within a municipality's boundaries. This permit ensures that the proposed development complies with the municipality's land use bylaws, zoning regulations, and other development standards.	Municipal	Municipality	6 months	Required
Municipal Authority	Building Permit	A building permit is required for any construction or renovation work on a building or structure within the municipality's boundaries. The permit ensures that the	Municipal	Municipality	6 months	Required

Legislation/ Regulation	Type of Approval	Description	Level of Government	Jurisdiction	Timeline	Applicability
		construction meets the requirements of the Alberta Building Code and other applicable regulations.				
Municipal Authority	Land Use Bylaw Approval	Municipalities in Alberta have their own land use bylaws, which set out the permitted land uses and development regulations for different areas of the municipality. Before any development can occur, it must comply with the land use bylaw for the area.	Municipal	Municipality	6 months	Required
Municipal Authority	Fire and Safety Code Compliance	Depending on the type of development proposed, the municipality may require compliance with safety and fire codes to ensure the safety of workers and the surrounding community.	Municipal	Municipality	6 months	Required

12. Indigenous and Community Engagement Plan

Engaging early with Indigenous and non-Indigenous communities is an essential part of any project's master planning process – particularly when discussing new technology associated with nuclear energy, which is tantamount to introducing a new industry.

The Government of Alberta (GoA) has publicly endorsed the federal government's SMR Action Plan and jointly released *A Strategic Plan for the Development of Small Modular Reactors* with the governments of Saskatchewan, Ontario, and New Brunswick. As of March 2023, the GoA, through Invest Alberta Corporation, signed MOUs with SMR developers, ARC Clean Technology Canada and Terrestrial Energy, to expand operations to Alberta.

It is important to note that nuclear will be a new industry for the province which will require extensive public education and engagement as well as the development of a new provincial regulatory framework. It will also be an industry that is regulated federally, requiring involvement of the CNSC and the IAA. These additional elements can pose challenges to the project but can be mitigated by early and effective engagement. The government alongside the project proponent will play an active role in the public and Indigenous engagement process.

12.1 Case Studies

The following case studies demonstrate different engagement approaches undertaken by proponents pursuing nuclear projects in Canada.

12.1.1 Case Study 1 – SaskPower

SaskPower is currently planning for nuclear power in the province in the form of an SMR. It has been holding information sessions and conducting public engagement with Indigenous and non-Indigenous communities since spring 2021. It has taken a rigorous, transparent, and informative approach to advanced engagement to create relationships and encourage buy-in.

SaskPower has undertaken a government-led approach to engagement by engaging with the public, academia, business associations, and communities directly through its series of information sessions. Both Indigenous and non-Indigenous communities are interested in the safety and longevity of nuclear energy, public health, and general community impacts.

Communities are generally concerned about how SMR projects can affect the environment. The impact on water – although minimal with SMR's – is a key concern since there is a belief that SMRs need to be located near water. General community issues about SMRs include concerns about contamination, impacts to fish and wildlife, impacts on agriculture, and recreational use. Fuel and waste management are also prevalent concerns.

The First Nations Power Authority (FNPA) facilitated information sessions with First Nations and Métis communities in Saskatchewan; publishing its findings on behalf of SaskPower in the fall of 2021. These sessions were meant to build relationships and share information.

12.1.2 Case Study 2 – NB Power

Based in New Brunswick, NB Power's Point Lepreau Nuclear Generating Station (PLNGS) is a Canadian Deuterium-Uranium (CANDU) pressurized heavy water (PHW) facility which began commercial operation in 1983 and was refurbished between 2008 and 2012.[98]

NB Power's First Nation and Public Affairs team approaches consultation based on three pillars:

- Engagement and Community Relations – building relationships and meaningful engagement.
- Education, Cultural Awareness and Sensitivity – educating the organization on understanding and appreciating First Nations culture, improving communications and relationships.
- Employment – facilitating employment and capacity building opportunities for First Nations (i.e., including community members as subcontractors when practical).[99]

PLNGS is Atlantic Canada's only reactor and often supplies at least one-third of New Brunswick's total annual electricity output. After hydropower, nuclear power is New Brunswick's least expensive power source. It is a high-density and efficient form of energy generation.

NB Power publishes a quarterly community newsletter called *From the Point*, which updates the surrounding communities on plant activities, community partnerships, the regulatory process, and other topics of interest.[100] It also has a Community Liaison Committee which meets to bring forward questions and concerns from community members, organizations, and industries located near the PLNGS and to share information about its operations.

12.1.3 Case Study 3 – Ontario Power Generation (OPG)

OPG pursued the Darlington New Nuclear Project (DNNP); an SMR, in addition to different options for a waste management facility and has taken a proactive approach with engagement. OPG has been updating Indigenous communities, communities, and the public since the project's inception in 2006. These records of engagement were used in the OPG's application to the CNSC for the site preparation licence renewal.[101]

The DNNP is as an energy source which can avoid carbon dioxide (CO_2) emissions while maintaining a smaller footprint than other renewable energy sources. Nuclear is widely regarded by the public as being an environmentally friendly form of energy generation with limited negative environmental impacts.

[98] https://www.nuclearsafety.gc.ca/eng/reactors/power-plants/nuclear-facilities/point-lepreau-nuclear-generating-station/index.cfm..
[99] https://www.nbpower.com/en/about-us/in-the-community/first-nations-relations/.
[100] https://www.nbpower.com/en/about-us/in-the-community/point-lepreau-nuclear-generating-station/from-the-point/.
[101] https://www.nuclearsafety.gc.ca/eng/the-commission/hearings/cmd/pdf/CMD21/CMD21-H4-1.pdf.

Since 2006, OPG has kept Indigenous partners, the public, and the communities updated on the regulatory process, site preparation, and next steps. Since 2012, OPG has communicated about DNNP through various methods:

- Information sharing:
  - Fully staffed DNNP public information centre.
  - Information available at OPG.com.
  - Toll-free information line.
  - Social media platforms (i.e., Facebook, Twitter, and Instagram).
- Community outreach:
  - Briefings with key stakeholder groups, elected officials, and municipal representatives.
  - Presentations and site bus tours of the Darlington site (including the DNNP lands) to community groups, key stakeholders, industry partners and the general public.
  - Quarterly Neighbours Newsletter for the DNNP:
    - Distributed to about 120,000 residents and businesses within 10 kilometres of the site.
    - Posted online.
  - A DNNP booth and information available at the station's annual public open house (annual attendance is about 3,000 people).
- Community Committees:
  - Regular updates to established local community committees including the Darlington Community Advisory Council, Pickering Nuclear Community Advisory Council, Durham Nuclear Health Committee.
  - Clarington Board of Trade and Office of Economic Development.[102]

12.2 Indigenous and Community Engagement Approach

The proposed stakeholder engagement approach will incorporate the known regulatory consultation processes as defined by the CNSC and the IAA and a proponent-led stakeholder engagement approach. There will likely be a provincial engagement and consultation approach to consider, which has not yet been defined. It is important to note that many Indigenous communities also have their own consultation and engagement processes. Proponents will need to understand those processes and whenever possible, respect the community processes in alignment to processes defined by the regulator. Furthermore,

[102] Clarington Board of Trade | Our business is supporting your business. (cbot.ca).

Indigenous Peoples have constitutionally protected Aboriginal and Treaty rights, which must be considered in any engagement process.

12.2.1 Regulatory and Consultation Engagement Process

The nuclear regulatory bodies have defined the public and Indigenous engagement process to achieve adequacy for regulatory consultation as defined by the federal regulatory process. In Canada, all nuclear energy projects producing 200 megawatts thermal (MWth), or more are required to file regulatory applications through the federal IAA and CNSC.

The regulatory review process is triggered immediately upon submission of any regulatory applications and/or a project description. The IAA must approve an impact assessment phase before any licences can be granted by the CNSC. These applications are separate but there is overlap between the CNSC and IAA review timelines.

The IAA recommends the proponents of all major projects engage with the IAA in advance of submitting an initial project description to ensure the proper documentation is prepared for submission, ultimately supporting a more efficient and timely planning phase.[103] It also recommends other federal agencies, such as the CNSC, be contacted in advance to ensure project proponents are aware of other regulatory documents it may need to provide. In doing so, proponents would be provided with a fulsome list of Indigenous communities and Stakeholders to be engaged with before and during the regulatory review process, as well as what that engagement should look like.

According to the IAA, public participation and Indigenous consultation needs to begin during a project's planning phase[104] *before* the impact assessment, which would be triggered upon the proponent filing a project description. The planning phase needs to include a Public Participation Plan that provides proponents, the public and others with certainty about how participation occurs.[105]

An Indigenous Engagement and Partnership Plan (IPP) will also be created during the Planning Phase by collaborating with Indigenous communities as identified by the IAA. This plan is required by the IAA and should be a high-level outline of how communities will participate in the federal impact assessment process.

In 2021, the federal government provided a Royal Assent, which put into force the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP), known as Bill C-15, the UNDRIP Act. Furthermore in 2023, the federal government issued its draft UNDRIP Action Plan on their planned implementation. The integration of the UNDRIP Act into the SMR regulatory process is unclear at this time and needs to be further defined.

Through these processes, proponents are expected to have demonstrated it has conducted meaningful, not transactional, consultation with these Indigenous communities and

[103] Guide to Preparing an Initial Project Description and a Detailed Project Description - Canada.ca.
[104] Public Participation - Canada.ca.
[105] Overview of Public Participation Plan - Canada.ca.

community members. Typically, “meaningful” consultation means listening to, discussing and being prepared to address Indigenous Peoples' concerns.[106]

Under the federal government’s Duty to Consult, the IAA would also engage with the pre-determined Indigenous communities during the impact assessment review.

The steps to achieve Adequacy for Regulatory and Consultation Engagement are outlined in Table 12-1.

Table 12-1: Steps to Achieve Adequacy for Regulatory and Consultation Engagement

Action	Trigger	Government		Details
		Federal	Provincial	
Proponent to engage regulators	Before submitting initial regulatory applications	IAA CNSC	To be confirmed	The IAA will determine which Indigenous communities and stakeholders should be engaged. Courtesy given to provincial government regarding consultation. Further detail can be provided following establishment of a provincial nuclear regulatory framework.
Planning Phase and Community Engagement	Prior to submitting initial project description	IAA	To be confirmed	Includes public feedback and input, identifies public participation objectives, engagement opportunities at each phase of process and methods of engagement.
Public Participation Plan	Included in the Planning Phase	IAA	N/A	Provides certainty how participation among all stakeholders will occur
Indigenous Engagement and Partnership Plan	Including in the Planning Phase. Posted to IAA registry 180 days after initial project description is submitted	IAA	Indigenous communities pre-determined by IAA	High-level outline which and how groups will participate in the impact assessment
Initial project description	Initiates impact assessment phase	IAA		
Licence to Prepare Site application	Initiates regulatory review process	CNSC		
CNSC regulatory review and IAA		IAA		

[106] Meaningful Consultation with Indigenous Peoples (ictinc.ca).

Once the federal regulatory review process has been triggered – which includes the IAA's impact assessment review – the process would take a minimum of seven years, depending on whether all regulatory and licensing applications meet stipulated federal requirements. A Regulatory Engagement Roadmap of SMR Development can be found in Figure 11-1.

12.2.1.1 Opportunities and Challenges

The regulatory-defined engagement process outlines the IAA's mandatory federal requirements up front, including the need to develop an IPP during the Planning Phase prior to submitting an initial project description and/or a Licence for Site Preparation.

Although this scenario meets regulatory requirements, and by utilizing this scenario only, the proponent risks Indigenous communities and stakeholders near the proposed site perceiving this action as "minimally compliant" or providing the bare minimum.

Another potential challenge is the relative infancy of the IAA. Established in 2019, less than one year before the COVID-19 pandemic began. There have been few major projects announced, particularly in the nuclear industry. At present, OPG's SMR at its existing Darlington facility predates the creation of the IAA and they do not have to participate in this process. Its application for Licence for Site Preparation was previously approved by the CNSC in 2012.

A list of the potential opportunities and challenges associated with the Adequacy for Regulatory Consultation approach can be found in Table 12-2.

Table 12-2: Opportunities and Challenges for Regulatory Consultation and Engagement

Issue	Opportunities	Challenges
Setting expectations with Indigenous and non-Indigenous communities prior to Final Investment Decision (FID)	Provide IAA with IPP in advance of regulatory submission, provides early insight into community issues and concerns	Advance public disclosure of proposed project in advance of initiating regulatory process
Efficient process	Maximize investment to meet with communities identified by IAA	Follow-up activities may be necessary to meet evolving IAA guidelines for IPP
Engagement scope	Allows the focus to be on communities inside the region	Potential for additional engagement with IAA communities in accordance with evolving IAA guidelines
		IAA could decide to increase scope of engagement beyond initial list of Indigenous communities.

Issue	Opportunities	Challenges
Federal implementation of UNDRIP Act (Bill C-15)	Uncertainty of the implementation of the UNDRIP Act throughout federal processes and laws	Work alongside the federal government and Indigenous communities to better understand and support the implementation process through cross-collaboration
Overlapping jurisdiction between the federal and provincial government	Federal and provincial governments would benefit from a coordinated process including the Indigenous communities engaged, level of engagement and methods of engagement	Work collaboratively to develop a coordinated process between Indigenous communities, federal government, provincial government, and industry

12.2.1.2 Timeline

Figure 12-1 outlines the forecasted timeline for Regulatory Consultation and Engagement.

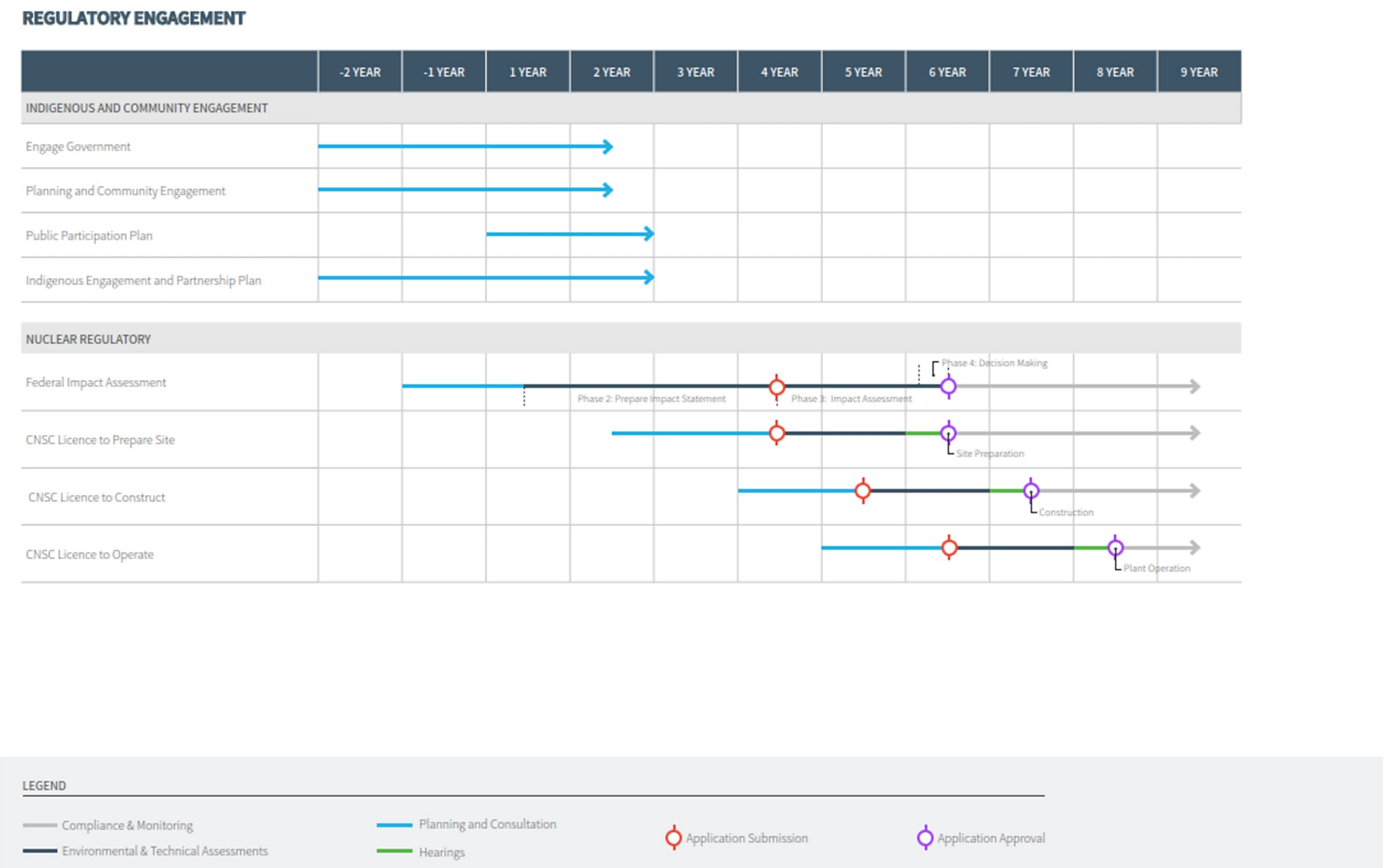


Figure 12-1: Regulatory Consultation and Engagement Roadmap

12.2.2 Proponent-Led Engagement

In addition to the Regulatory Consultation and Engagement defined in the previous section, proponents recognize that a significant amount of time – up to four years, may be needed to ensure engagement meets all expectations under the IAA, CNSC, the federal government's Duty to Consult[107] and public expectations of engagement.

The GoA has publicly committed to developing SMR technology as a means of decarbonization. Engaging early with the Premier's Office, Alberta Energy, Alberta Environment and Protected Areas, AER and AESO at least three years in advance of filing an initial project description will demonstrate the Proponent's desire to work collaboratively with government and regulators.

Through collaboration with the GoA, the Proponent can ensure information about SMRs is being properly socialized and the public are educated about the SMR technology prior to the project definition. Rather than focusing engagement on any one area specifically, the GoA could launch a province-wide campaign aimed at informing and educating about SMRs. Initial communications could include:

- Mail-out pamphlets and fact sheets about SMRs to all Albertans.
- Creation of a provincial webpage/website dedicated to information about SMRs, including online feedback mechanisms.
- Next actions would include scheduling a series of public information sessions in each quadrant of the province. Communications tools used in the public information sessions would include, but aren't limited to:
  - Virtual and/or in-person public information sessions or community roundtables, including formal presentation describing SMR technology and rationale behind provincial support for SMRs including:
    - Summary of the engagement process.
    - Outline of future participation processes.
    - Site considerations.
    - Economic opportunities.
    - Third-party subject matter experts from CNSC, NWMO, CNA.
    - Introduction of feedback mechanisms (i.e., feedback forms, online feedback submissions).
    - Question-and-answer period.
  - Direct engagement with municipal governments.

[107] Government of Canada and the duty to consult (rcaanc-cirnac.gc.ca).

- Direct engagement with First Nations and Métis governance councils.

Concurrent with the government's public engagement, the Proponent would begin its own enhanced engagement efforts with Indigenous and primary communities – later extending to secondary communities. This initial engagement would begin by reaching out to band councils and municipal governments to share the Proponents plans for a proposed SMR. From there, public information sessions, led by the Proponent, would be scheduled to meet with community members to begin discussions about the project.

Through feedback received during the public information sessions, the Proponent would be able to identify and respond to specific community concerns about the proposed SMR. As well, this would provide the Proponent with an opportunity to begin exploring potential partnership models such as equity ownership, community benefits, funding for education and skills training, among others. The transparency and collaboration in this level of Proponent-led engagement would empower communities, and potentially lead to individuals and/or communities championing the project.

The steps to achieving Proponent-Led engagement are outlined in Table 12-3.This will be undertaken alongside Regulatory Consultation and Engagement.

Table 12-3: Steps to Achieve Proponent-Led Engagement

Action	Trigger	Government		Details
		Federal	Provincial	
Proponent to engage government	Before submitting initial regulatory applications	IAA CNSC	To be confirmed	The IAA will determine which Indigenous communities and stakeholders should be engaged. Initiate discussions with GoA to determine provincial commitment to SMRs. Engage with provincial departments and agencies to determine regulatory requirements regarding infrastructure, environment, power generation, etc.
Primary Indigenous partners	Concurrently with government	Proponent-led		Indigenous communities located or having traditional territories within 50 km of proposed site
Primary stakeholder engagement	Concurrently with government	Proponent-led		Communities located within 50 km of proposed site
Engage with Albertans	6 months after initial engagement with government	Provincial government (departments and regulatory bodies to be determined)		Engagement with all Albertans

Action	Trigger	Government		Details
		Federal	Provincial	
Secondary stakeholder engagement	6 months after initial engagement with government	Proponent-led		Communities located within 100 km of proposed site
Establish Government-Led Panel	1 year after primary engagement begins	GOA		Meets quarterly
				Comprised of community, industry, municipal government, academia, special interest group representatives
Engage with special interest groups	1 year after primary engagement	Proponent-led		Meet with advocacy associations and special interest groups
Summary report	2.5 years	GOA		Publications of engagement topics and responses from Proponent-led engagement

12.2.2.1 Opportunities and Challenges

Engagement would be catered to ensure Indigenous and non-Indigenous communities understand the project, are able to provide direct feedback, and support for the project proceeding.

A list of the potential opportunities and challenges associated with Proponent-Led Engagement can be found in Table 12-4.

Table 12-4: Opportunities and Challenges for Proponent-Led Engagement

Issue	Opportunities	Challenges
Decision making process	More consideration would be given to communities' input. All community members would be involved in the process	
Catered engagement	Reinforces commitment to communities	May extend timelines for development
	Address community concerns directly	

Issue	Opportunities	Challenges
Dissemination of information	Demystify nuclear development	May need to share more about the project with having all of the details solidified (i.e., SMR technology, vendor selected, etc.)
	Discuss project directly, while answering questions about SMRs	
	Open forum to discuss project	
Engagement with government	Reinforces federal and provincial commitments to SMR development	Coordination with multiple levels of government and departments/agencies
		May be competing priorities among government agencies

12.2.2.2 *Timeline*

Figure 12-2 outlines the forecasted timeline for the Proponent-Led Engagement.

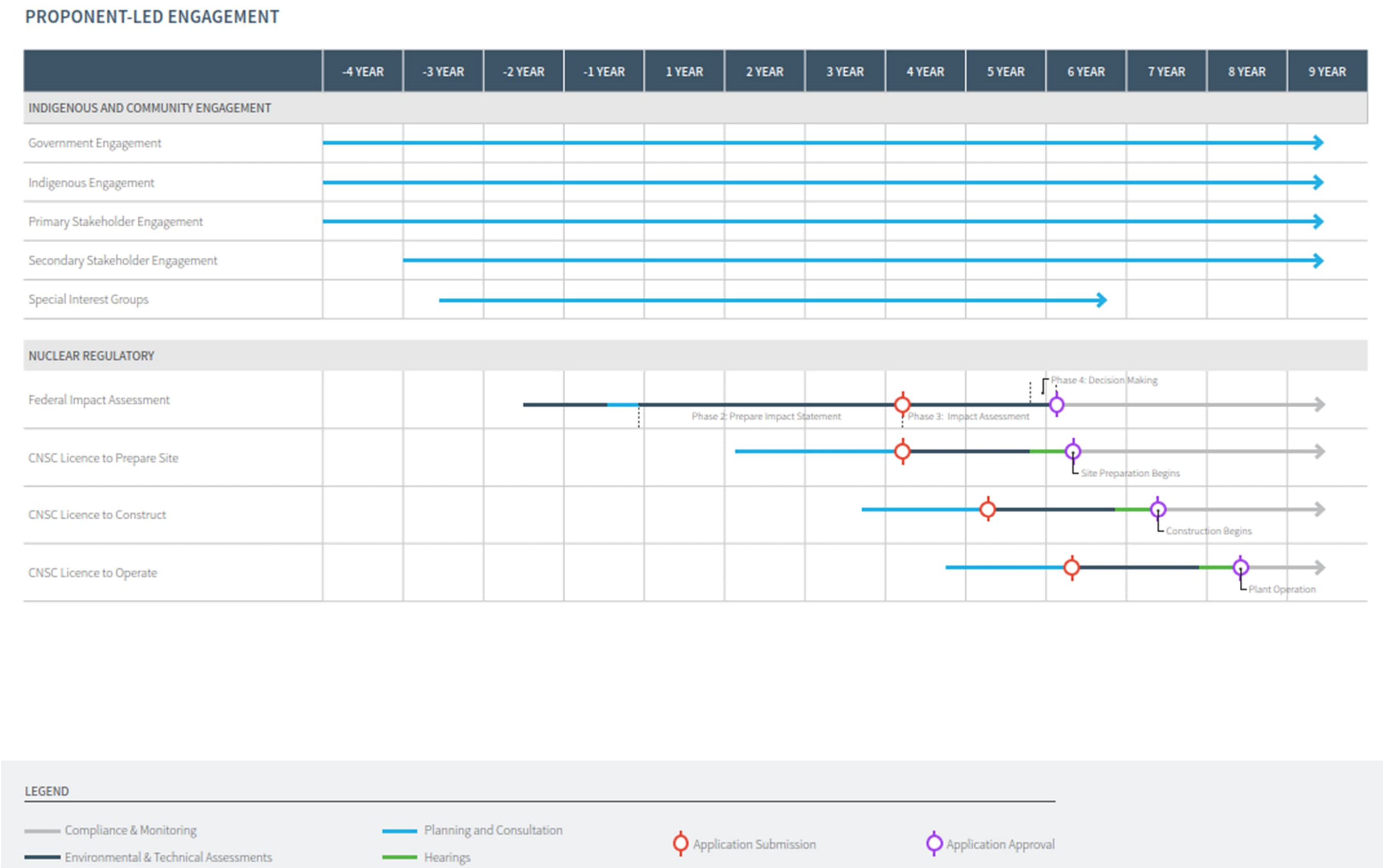


Figure 12-2: Proponent-Led Engagement Roadmap

13. Preliminary Project / Construction Execution and Planning

A project execution plan for a large-scale project, outlining the key components and strategies required for successful project implementation, will be required for any SMR project in an oil sands application. Project execution plans typically detail the project's objectives, scope, stakeholders, schedule, resource allocation, risk management, and communication strategy. Additionally, it highlights the importance of execution strategy models in guiding the project's progress and ensuring its ultimate success. A summary of key elements of a preliminary project execution plan is presented below:

Project Objectives: This section states the primary objectives of the project and desired outcomes and/or deliverables. These objectives serve as the foundation for all project activities and will be closely monitored throughout the execution phase.

Project Scope: The project scope defines the boundaries and parameters of the project, including the tasks, activities, and deliverables that will be undertaken. It identifies the project's limitations and clarifies what falls within or outside the project's purview.

Stakeholders: Identifying and engaging with project stakeholders is crucial for effective project execution. The detailed plan will include an analysis of key stakeholders, their roles, responsibilities, and expectations. Strategies for stakeholder engagement and communication are also outlined to ensure their active participation and support throughout the project lifecycle.

Timeline: The project execution plan will incorporate a comprehensive timeline that outlines the major milestones, activities, and their estimated durations. The timeline provides a clear roadmap for project implementation, enabling effective scheduling, resource allocation, and progress monitoring.

Resource Allocation: Efficient allocation of resources, including human, financial, and physical resources, is essential for successful project execution. The plan will outline the resource requirements and allocation strategies to ensure that the right resources are available at the right time, minimizing bottlenecks and optimizing project progress.

Risk Management: Identifying and mitigating potential risks is vital to minimize project disruptions and ensure its successful completion. The execution plan includes a risk management strategy that assesses potential risks, defines mitigation measures, and establishes contingency plans to address unforeseen challenges.

Communication Strategy: Effective communication is crucial for project success, ensuring that information is shared among team members, stakeholders, and relevant parties in a timely and accurate manner. The plan includes a communication strategy that outlines the channels, frequency, and methods of communication to foster collaboration and maintain transparency throughout the project.

Execution Strategy Models: Execution strategy models provide frameworks and methodologies that provide the basis to execute a project. They may include commercial models such as fixed price (lump sum) or cost reimbursable, or project execution models such as Integrated Project Delivery. Defining the execution model(s) streamlines processes, can support the optimization of resource utilization, and can enhance project flexibility.

In conclusion, the project execution plan provides a comprehensive roadmap for the successful implementation of a large-scale project. By addressing key elements of project management, such as objectives, scope, stakeholders, timeline, resource allocation, risk management, and communication strategy, the plan aims to ensure efficient project execution. Additionally, the utilization of appropriate execution strategy models offers a structured approach to project management, fostering adaptability, and maximizing the project's chances of success.

The Project Execution Plan (PEP) identifies the overall strategy to execute the project and is tailored to incorporate all the project specific requirements. The execution methodology adopted for this project should be aligned to accomplish the following projects critical objectives:

- Achieve or exceed safety plan goals.
- Deliver the project within budget and contractual terms.
- Deliver the project within the agreed to timelines (schedule).
- Provide value through the project delivery skills and innovation of the project team and subcontractors.
- Meet all regulations, codes & standards, and quality criteria.
- Coordinate work as required with other on-site contractors and stakeholders as required throughout the project.

13.1 Project Lifecycle

The project lifecycle is the process of developing a project from a concept to a finished operating facility. The process utilizes a stage gate system that requires completion of appropriate engineering and capital cost estimates before the stage gate can be completed, and the project sent for authorization to proceed to the next step in the process.

13.2 Cost, Time, and Scope (CTS) Plan

The key to a successful capital project is to manage scope, cost, and schedule. All three must be managed carefully to ensure project success. The purpose of the stage gate systems is to ensure that all are carefully considered, understood, and approved at each stage of the process. Each of these is developed and matures during each stage of the process.

13.2.1 Project Scope of Work

Development of the project scope of work is a key activity during the initial phases of the project development.

- In the Opportunity Assessment Stage, the options are identified and broadly compared. Some down selection is done in this stage, but generally, viable options are carried to the next phase.
- In the Scoping and Selection Stage the options are evaluated, and the best option is selected.
- In the Project Definition Stage engineering is significantly advanced on the chosen option to clearly define the required design basis, and overall project scope of work.

13.2.2 Project Estimate

The project cost is a buildup of the complete Capital Cost Estimate (CAPEX) including all direct costs, indirect costs, owner's costs, taxes, and contingencies. The CAPEX is built up over the lifecycle of the project. The accuracy of the estimate is dependent on the level of engineering completed and the accuracy of the information provided by the suppliers.

Estimates are typically developed using the AACE International Cost Estimate Classification System. Estimate classes varies from 1 to 5 with Class 1 being the highest level of accuracy. The level of accuracy (see Table 13-1) used in this study is Class 5 as no significant engineering has been performed to support a higher level of accuracy.

Table 13-1: Generic Cost Estimate Classification Matrix

	Primary Characteristic	Secondary Characteristic			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of Complete Definition	**END USAGE** Typical Purpose of Estimate	**METHODOLOGY** Typical Estimating Metho2	**EXPECTED ACCURACY RANGE** Typical +/- Range Relative to Best Index of 1 [a]	**PREPARATION EFFORT** Typical Degree of Effort Relative to Least Cost Index of 1 [b]
Class 5	0% to 2%	Screening or Feasibility	Stochastic or Judgement	4 to 20	1
Class 4	1% to 15%	Concept Study of Feasibility	Primarily Stochastic	3 to 12	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Mixed, but Primarily Stochastic	2 to 6	3 to 10
Class 2	.0% to 70%	Control or Bid/Tender	Primarily Deterministic	1 to 3	5 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Deterministic	1	10 to 100

Notes:
[a] If the range index value of "1" represents +10/-5%, then an index value of 10 represents +100/-50%
[b] If the cost index value of "1" represents 0.005% or project costs, then an index value of 100 represents 0.5%

As the project progresses through the development process, the level of engineering definition increases, the estimate accuracy improves, and contingency is reduced as shown in Table 13-2.

Table 13-2: Estimate Maturity vs Estimate Accuracy

PLP	FEL1	FEL2	FEL3	FEL4
	Conceptual Study	Pre-Feasibility Study	Feasibility Study	Implementation
Typical Approach	Factored	PFDs Budget Quotes	P&IDs & MTOs, Budget & Firm Quotes	Firm Quotes detail MTOs
Typical Engineering Definition	1% to 5%	5% to 20%	30% to 40%	50% to 100%
Typical Accuracy	+/-30%	-10% to +20%	+/-10% to 15%	+/-10%
Typical Contingency	20% to 30%	15% to 20%	10% to 15%	<10%

AACE has a specific cost estimate classification that applies to the Nuclear Industry: 115R-21: Cost Estimate Classification System – As applied in engineering, procurement, and construction for the Nuclear Power Industries.

During a project, the costs of the Nuclear Power Island are very dependent on the maturity of the reactor design. The costs of the balance of plant are typically based on mature designs and existing plants, so the ease and quality of the estimates for this portion of the project will be much better. The cost of the Nuclear Power Island will continuously evolve as the project continues from stage to stage.

13.3 Engineering Execution Plan

The engineering execution plan section of the PEP will present the engineering approach, scope, processes, and procedures that support the procurement of equipment and construction.

Engineering Objectives are to:

- Provide technical data (plans, designs, specifications, and drawings) that have an appropriate level of detail to allow for cost effective "on time" execution of procurement, fabrication, construction, and commissioning.
- Provide a purpose designed facility that is safe to construct, operate and maintain.
- Provide a facility that is designed to meet the required capacity and supports start-up with no incidents or faults.

The approach to engineering will complement the System Engineering Management Plan (SEMP) is to:

- Review the open items and the recommendation in the previous phase to address any gaps noted.
- Identify value engineering opportunities that may impact cost, schedule, and present them for review and approval.
- Manage interfaces between system design requirements.
- Identify requirements applicable to the plant (including the nuclear island and conventional island) and interface client leads for alignment.
- Adopt an engineering approach that continues to enhance collaboration between different contractors.
- Bring experience in delivery projects, by hiring senior engineers in all disciplines to support the technical teams.
- Identify specialists and other consultants to review or check our deliverables to ensure conformity with codes and local practices.
- Incorporate safety in design principles from the beginning to address and mitigate hazards.
- Set up well defined processes and procedures early in detailed design.
- Finalize the plant layout as early as possible to minimize change of the mass-production deliverables (e.g., isometrics).
- Develop appropriate detailed engineering solutions for the Project with respect to quality, schedule, and cost.
- Ensure design requirements and objectives that are in the design criteria, standards and specifications are met and incorporated.
- Specify and procure equipment and materials for this Project.
- Ensure that vendor certified data is incorporated into the design to avoid costly changes in the field.
- Align engineering to an approach that minimizes site construction activities and maximizes construction progress during the inclement months.
- Prepare definitive design bases and Engineering Work Packages (EWPs) that are aligned with construction activities organized in Construction Work Packages (CWPs).
- Ensure sufficient engineering maturity is achieved prior to engineering information being released to fabrication and construction contractors to facilitate efficient fabrication practices and minimize risk of rework.

- Issue engineering deliverables to support the scheduled execution of procurement, logistics, fabrication, installation, commissioning, start-up, and operation of the facility.
- Manage the detailed design and have responsibility for the quality and schedule, with Owner representatives monitoring the detailed engineering work including appropriate review and approval of deliverables.
- Integrate Owner/Operator, Constructor and Owner/Operator team members in design reviews, with emphasis on constructability, safety, operations, and maintenance.
- Take ownership and responsibility for the technical outcome and engineering product.

As the project progresses, the Engineering Execution Plan expands to include the following:

- Summary of Engineering Work.
- Engineering Deliverables.
- Engineering Execution Strategy.
- Planning and Control, Engineering Methodology.
- Hazard Analysis, Engineering Quality.
- Systems/Tools to be leveraged for the engineering phase.

13.3.1 Engineering of the Nuclear Island

The design of a nuclear power plant is typically split into two distinct sections to reduce the complexity of the design process. These two sections are the Nuclear Island, and the balance of plant or conventional island. This is done because a more rigorous quality management system must be applied to the Nuclear Island which increases overall engineering, material, and construction costs.

There are specific standards that apply for design of nuclear systems in Canada. A summary of some of the key standards is as follows:

- CSA N286-12 – Management System Requirements for Nuclear Facilities.
- CSA N299 – Quality assurance Requirements for the Supply of Items and Services for Nuclear Power Plants.
- CSA N285-12 – General Requirements for Pressure-Retaining Systems and Components in CANDU nuclear power plants.
- CAN/CSA ISO 9001:16 – Quality Management System Requirement.

The most important of these for the design process is CSA N286-12. The primary considerations are:

- **General:** The design process shall be established and controlled.
- **Inputs:** Design inputs shall be established.

- **Requirements:** Design requirements shall be defined in sufficient detail to provide refence for making decisions, verifying designs, and evaluating design changes.
- **Tools:** Design tools shall be appropriate for the application and controlled.
- **Design:** The design shall be carried out based on the design requirements. Design Specification, calculation, analysis, and studies shall be controlled in such a manner that they are available to subsequent users of the design.
- **Documents:** Design documents shall be created so that the design can be related to the design requirements and used by organization responsible for construction, commissioning, operation, and decommissioning.

For the Nuclear Island, delegating overall design authority to the selected SMR technology vendor should be considered within the overall project management system framework. As this portion of the facility design will be common to all of the nuclear facilities that the supplier provides, they can standardize the design and use common designs across multiple applications reducing the individual cost.

13.4 Procurement and Contracting

The Procurement and Contracting section of the PEP defines the methodology for controlling cost and schedule via contracts and agreements with key stakeholders and suppliers. To develop the detailed Procurement and Contracting plan it is necessary to first define a procurement and contracting strategy.

13.4.1 Project Structure and Delivery Model

The project execution strategy will identify an execution model, which may be one of an EPC/EPCM/IPD delivery model. Once the project delivery model is identified, a contracting strategy can be put in place. This section outlines possible project delivery models that could be adopted to implement the facility of interest.

13.4.2 EPC vs. EPCM vs. IPD

When it comes to executing a first-of-a-kind project, it is important to carefully consider the project delivery model that will be used. Engineering Procurement and Construction (EPC) and Engineering, Procurement, and Construction Management (EPCM) and Integrated Project Delivery (IPD) are commonly used models in the construction industry that can be applied. Each approach has its own attributes and challenges, and the choice between them ultimately depends on the specific needs of the project and the owner/client goals.

EPCM and IPD models have generally been favored by industry for first-of-a-kind projects, and each has its own benefits.

13.4.3 EPC

An Engineering Procurement and Construction (EPC) contract is a type of contract used in the construction industry where a single entity is responsible for delivering a project from design to completion, usually on a turnkey basis. This means that the contractor is responsible for designing, procuring, constructing, and commissioning the project within a specified budget and timeline.

13.4.3.1 Attributes of an EPC Model

The EPC contract is usually a fixed price contract, which means that the contractor agrees to complete the project for a fixed price, or lump sum. The lump sum will be determined based on the project scope, design, and specifications, as well as any risks or contingencies identified during the project planning process. This gives the client certainty over the cost of the project and incentivizes the contractor to complete the project on time and within budget.

Overall, an EPC lump sum contract is a comprehensive and structured approach to delivering a project, which aims to provide a high level of certainty for both the client and the contractor.

In an EPC lump sum contract, the contractor takes on the risk of cost overruns, schedule delays, and other risks that may arise during the project, so it is important to carefully define the scope of work and project specifications to avoid ambiguity and disputes.

13.4.3.2 Challenges of an EPC Model

To use an EPC model, the design should be well defined with limited potential for change to mitigate/manage overruns and delays construction phase. While the EPC model can be applied to novel technologies with an appropriate risk allocation model, there may be a higher degree of uncertainty within novel technologies leading to higher project cost due to uncertainty in quantities, specifications, and variability in execution.

In this model the contractor assumes the risk of cost overruns, which can be difficult to predict in advance on a first-of- a kind projects. To account for this, EPC contractors may include a substantial risk premium resulting in the client paying for risks whether they are incurred or not. The contractor is also ultimately responsible for the project meeting the performance requirements and may be liable for damages if performance, cost, or schedule milestones are not met. Consequently, if the contractor is financially stressed this may lead to poor quality of deliverables and construction execution.

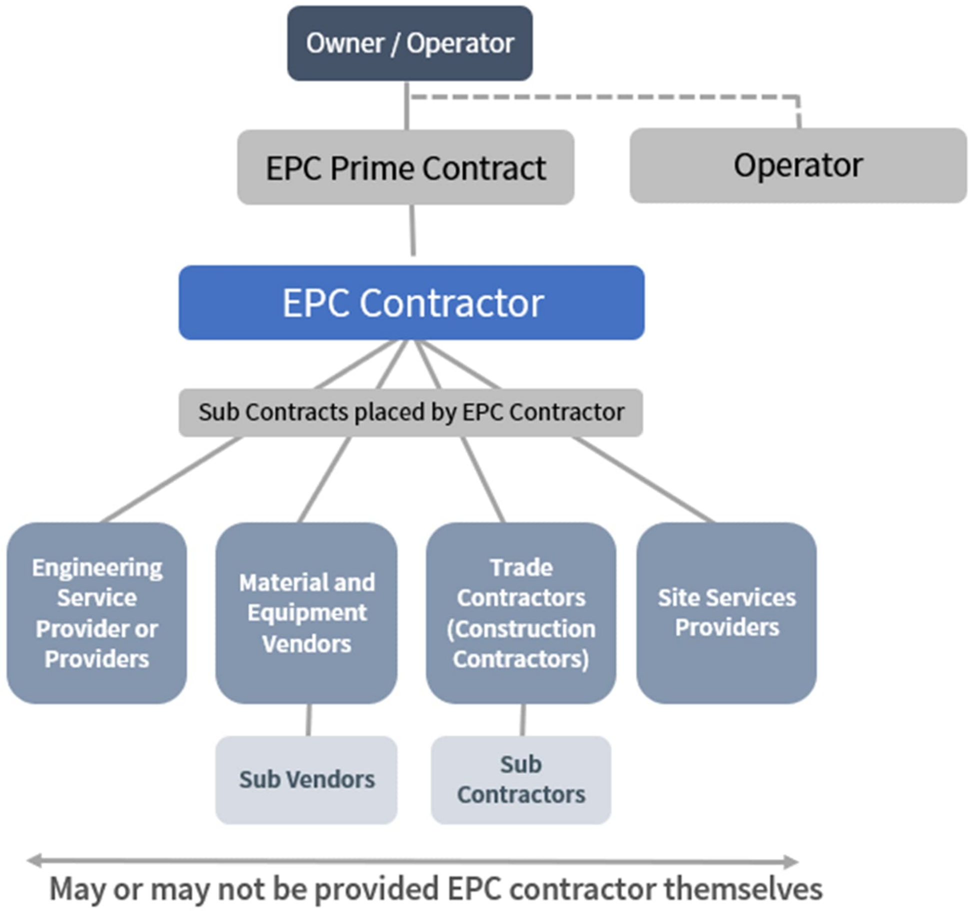


Figure 13-1: EPC (Lump Sum) Model

13.4.4 EPCM (Model)

EPCM is a traditional project delivery model that separates responsibility of each project stage. An EPCM contractor is appointed to act as the owners' agent, providing technical expertise and overseeing the overall execution of the project. Under the EPCM model, the engineering, procurement, and construction management functions are contracted to different contractors or companies, though it is typical for the EPCM contractor to perform some of these functions itself.

13.4.4.1 Attributes of EPCM Model

The EPCM model allows for greater flexibility and control for the owner, as they retain the ultimate responsibility and decision-making authority for the project.

The owner can then take advantage of the contractors' technical expertise and experience in managing complex projects.

The EPCM model often results in lower overall costs if managed well, as the risk premium inherent in the EPC model does not exist and only realized risks are mitigated. The project structure also allows the owner to contract with specialized vendors for each project stage, rather than relying on a single general contractor.

13.4.4.2 Challenges of an EPCM Model

The EPCM model can result in greater coordination challenges, as multiple contractors and vendors are involved in the project. The EPCM contractor may act as a project integrator to support the owner, but ultimately the owner may need to invest more time and resources in overseeing the project, as they are responsible for managing multiple contractors.

Due to the presence of multiple contracts, there is a greater risk of disputes arising between the contractors, which can delay the project timeline. The EPCM model also places a greater burden on the owner and EPCM Contractor to manage project risks, including technical, financial, and legal risks.

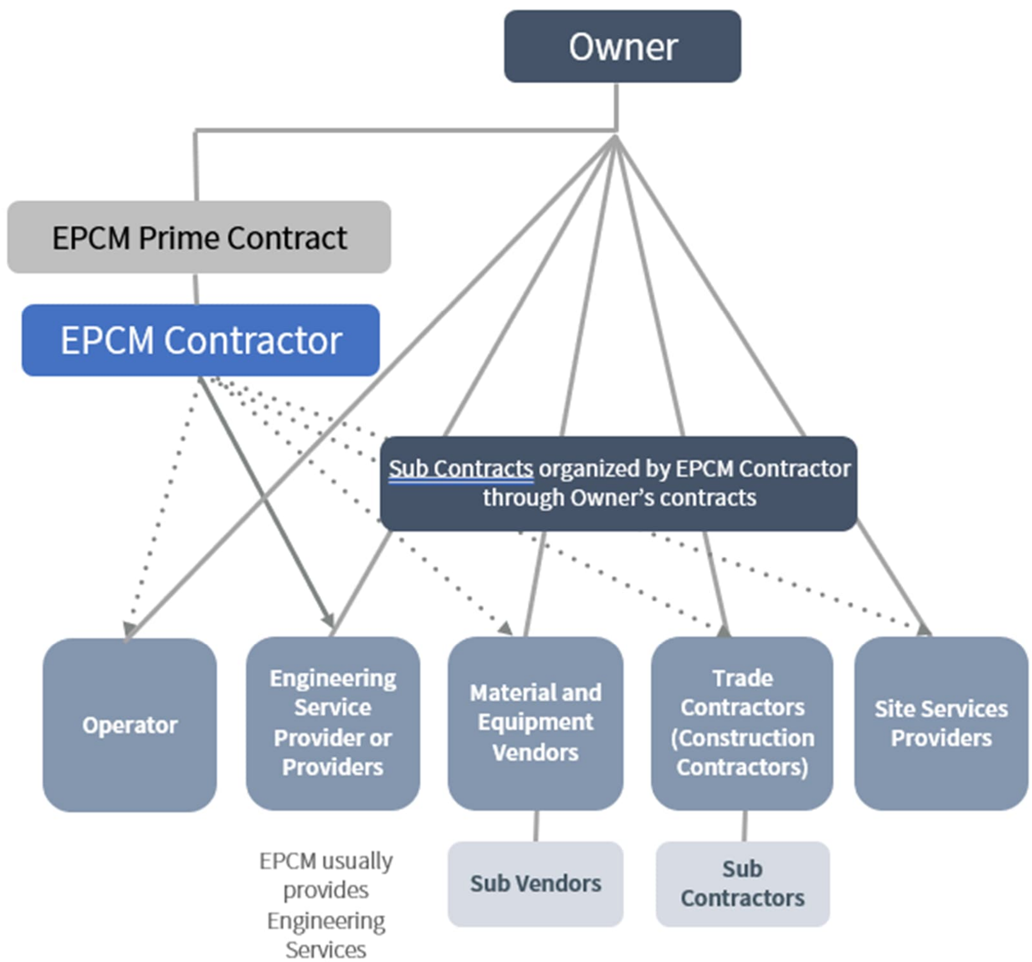


Figure 13-2: EPCM Model

13.4.5 Overview of an IPD Model

Integrated Project Delivery (IPD) is a collaborative approach that brings together all project stakeholders, including the owner, architect engineer, and contractors, in a single team. The IPD team works together to plan and execute the project, with all parties sharing in the project risks and rewards.

The model is well-suited to first-of-a-kind projects, as it allows all parties to work together to identify and manage project risks.

13.4.5.1 Attributes of an IPD Model

The IPD model requires a high level of collaboration and trust among all project stakeholders.

- **Collaboration:** The IPD model encourages collaboration and communication among all project stakeholders, resulting in more efficient planning and execution.
- **Risk Management:** The IPD model may result in higher upfront costs, as all stakeholders must invest time and resources in the planning stage.
- **Limited Control:** The IPD model may not be well-suited to projects where the owner wants to maintain full control over the project.

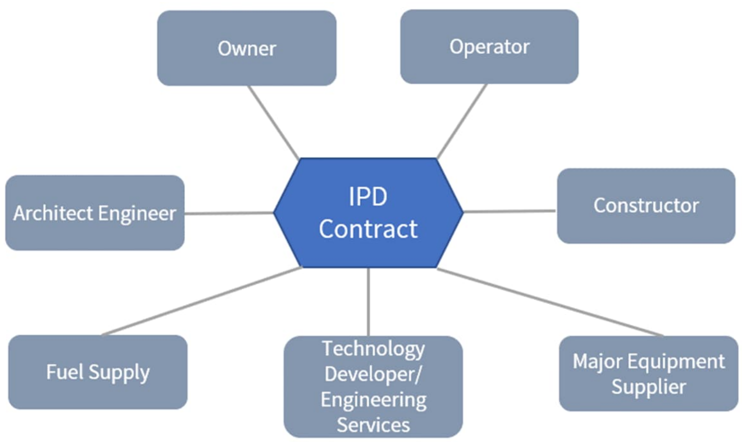


Figure 13-3: Integrated Project Delivery Model

13.4.6 Summary of Execution Strategies

Selecting a project delivery model will depend on the specific needs of the project and the client goals. Whether an EPC lump sum contract is advisable for a first-of-a-kind project depends on several factors.

- An EPC lump sum contract can be advantageous for a first-of-a-kind project because it provides a single point of responsibility and reduces the client's risk. The contractor is responsible for the entire project, from design to construction, and must deliver it within a fixed budget and timeline. This can help the client avoid the complexities and risks associated with managing multiple contracts and subcontractors.

- First-of-a-kind project may present unique challenges and uncertainties that could make it difficult to define the project scope and specifications with sufficient detail to ensure that the EPC contractor can accurately estimate costs and complete the project on time. The EPC contractor may also lack experience with the new technology or approach being used in the project, which could increase the risk of delays or cost overruns. Consequently, finding a contractor willing to take the upfront risks on-a-first-of a kind project may be hard to find.

The EPCM model may be preferred if the owner wants greater control and access to specialized technical expertise, while the IPD model may be preferred if collaboration, risk management, and transparency are essential for success. Ultimately, the choice between the models depends on the owners' priorities and the specific needs of the project.

13.4.7 Procurement Management

Regardless of which contract strategy is selected, the objectives of the procurement management plan are roughly the same. The objectives of the procurement and contracting activities are to support the project by:

- Ensuring the right equipment or material, is supplied at the right quality, in the right quantity, at the right time, from the right source, at the right price.
- Ensuring contractors are on site punctually and execute their scope of work as specified, at the right price and quality.

Procurement consists of:

- Materials Management – where materials integration will take place managing materials and equipment flow from requisition conception through to allocations at site in conjunction with following activities:
  - Purchasing.
  - Vendor Quality Surveillance.
  - Expediting, Logistics.
  - Site Materials Control.
- Contracts – including:
  - Contract Formation.
  - Contract Administration.
  - Performing accounts payable including forecasting cash calls.

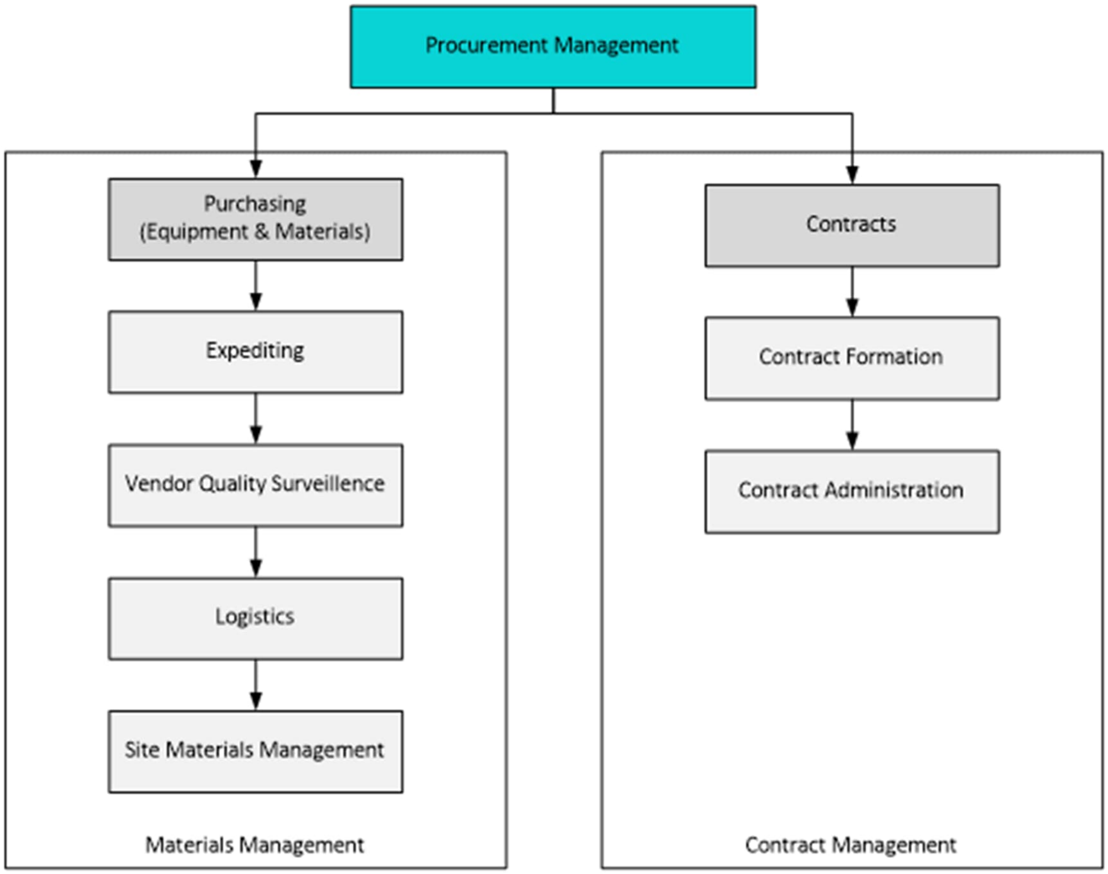


Figure 13-4: Summary of Procurement Activities

In conducting procurement activities for the Project, the following conditions will be satisfied:

- The overall procurement approach will be assessed for the project as this will depend on stakeholders that will operate as the owner's agent for procurement and contracts commercial activities.
- Overall development of each package will be supported by expression of interest (EOI's) prequalification ensuring capabilities known and investigated.
- Risk review workshops for all major critical packages where risks are known, and mitigation identified and addressed prior to Recommendation for Award (RTA) issuance.
- Allow risk register input in supporting mitigations, supported by risk register.
- Compliance with project criteria and specifications, including:
  - Operating within the project budget.
  - Executing to the project schedule.
  - Ensuring suppliers and contractors meet or exceed project quality standards.

In future project phases, the Procurement Management Plan will detail the responsibilities for procurement/contracts execution to leverage processes, systems, and tools for engineering delivery. This will include:

- Materials Management:
  - Including: tools, responsibility matrix, sourcing strategy overview, sourcing strategy approach, purchasing operational interfaces, purchasing process, bidding process.
- Vendor Quality Surveillance:
  - Including: : VQS inspector, program, supplier quality management reporting, contractor quality, and inspection program.
- Expediting:
  - Including: package kick-off meetings, vendor document expediting, vendor equipment and material expediting.
- Logistics:
  - Including: planning and shipping process, freight forwarder, packing and marking instructions.
- Site Materials Control:
  - Including: site material control process, storage and preservation of equipment, contractor supplied materials).
- Contracts:
  - Including: contracting strategy, contracting plan, approach, contract management objectives, contractor sourcing, contract formation, contract administration, risk management, change management).

13.5 Construction Execution Plan

The construction execution plan presents the contracting and construction strategies, approach, and sequencing that underpin the schedule and cost estimate.

The Project should be construction driven, in that the entire engineering, procurement and logistics effort is focused on enabling the construction of the Project in a safe, efficient, and timely manner. Construction key objectives are to:

- Deliver a safe and environmentally compliant facility in a socially acceptable manner, and in accordance with the Project scope and specifications.
- Achieve Project completion within the agreed project schedule.
- Complete the Project within or under the budgeted amount.

- Construct a quality facility, which meets the defined Project objectives, using safe, practical and industry standard methods of construction.
- Perform all activities in a safe and effective manner, with zero recordable incidents.
- Ensure that all applicable regulations, licence conditions, specifications, and standards are met.
- Provide a positive working environment for all personnel resulting in a high level of motivation.

The Construction Management (CM) team is responsible for safety, quality, coordination, and management of the contractors, schedule and cost of the construction and pre-commissioning scope of work. The CM team is to be comprised of experienced and qualified construction professionals responsible for oversight and management of contractor performance, and management, coordination, and handover of the facilities to Operations.

The CM team will have within its organization various functional groups, namely Health, Safety and Environment (HSE), Construction Management, Site Management, Field Engineering and Quality, Procurement and Contracts, Site Materials Management, Administration, and Pre-Commissioning.

The CM team will be based at the project site and will mobilize according to the execution schedule and staffing plan. Certain members of the CM team will mobilize early during engineering and procurement phase of the Project. These CM team members will actively participate in constructability reviews, contractor evaluation and selection, contract formation, and other items as required.

The scope of the project is packaged into Construction Work Packages (CWPs) which form the basis in which the project master schedule is be developed. CWPs also form the basis for the management and control of the construction scope of work by the CM team. As the project progresses, CWP’s are updated and expanded as engineering is further developed and contracting plans are finalized.

The construction execution plan also includes responsibilities for construction management to leverage processes, systems, and tools for execution such as:

- Constructability reviews
- Temporary construction facilities
- Construction contracting strategy
- Heavy lifts and movements
- Non-destructive testing
- Field engineering
- Vendor representatives

- Site material management.

13.5.1 Constructability

SAGD facilities are located in the northern areas of Alberta. This area is characterized as boreal forest and wetlands and has areas that are commonly known as muskeg. During construction, permanent or temporary roads may cross the muskeg which is typically accomplished with geotextiles and corduroy roads.

In selecting the SMR site, the key is to pick areas of high ground for the process buildings. This is not foreseen as a significant difficultly as the areas where the SAGD sites exist typically have sufficient high ground to select from. The reactor building and associated outbuildings are not particularly large compared to a generic site footprint, and a proper building location is assumed to be available and steam and power routed to this location.

13.5.2 Modularization

Modularization is an important aspect of construction and an approach to ensure safety, reliability, and efficiency of the project execution. Once an SMR technology is selected for a site, it will be important to coordinate with the selected SMR vendor to determine the modularization strategy. There are several key steps that need to be taken during modularization strategy development including:

- Defining the system boundaries: determine the system boundaries that need to be modularized. This will identify the various components that need to be separated and modularized base on engineered items and ease of construction.
- Determining the interfaces: Once the modules have been identified coordination between the different modules will be required to ensure that the modules interact with each other effectively.
- Designing the modules: modules are to be designed to perform the specific functions and interface requirements.
- Testing and Integrating the modules: Test and integrate the modules into the larger systems to ensure that all modules work together effectively and efficiently.
- Throughout this process coordination is required with engineering and construction departments to ensure safety, reliability and efficiencies are applied for successful project execution.

13.5.2.1 Reactor Modularization

The M in SMR is modular. The key to keeping the reactor safe and relatively low cost is to modularize key aspects of the reactor design. Modularization in this case means manufacturing as much of the equipment as possible in a factory setting using standardized designs and proven tools and techniques. This maximizes quality and efficiency while minimizing site construction which is typically much more expensive and time consuming.

The primary issue with modularization of the reactor portion of the project is that the designs of SMRs are not advanced enough for commercial units to have been constructed. Modularization in a factory setting requires the design to be proven and relatively static. The roadblocks to this are:

- The facilities necessary require a substantial capital investment that needs to be recovered from a substantial number of manufactured units.
- The facilities and techniques need to be proven and accepted by the regulatory bodies for mass production.
- Experience from initial unit fabrication needs to be incorporated in the design and fabrication technologies for later units.
- Configuration stability must be established for each module to enable efficient modularization.

Being an early adopter of the technology will mean that the full benefits of modularization will not yet be established. The economies of scale will only be realized on ‘nth of a kind’ (NOAK) deployments. To overcome this, it may be necessary to find subsidies to compensate and encourage early adopters.

13.5.2.2 Balance of Plant Modularization

The nuclear power island is assumed to end at the perimeter of the reactor building with the remainder of the systems and site being of standard industrial construction. For the nuclear power island, systems are contained within the reactor building with a heat exchange media being piped from the reactor building to heat exchangers for electric power generation or process steam production. These areas are considered to be non-nuclear.

The balance of plant will generally consist of the steam generators, condensate system, feedwater system, pressure water piping, and any of the necessary connections to the process piping for feed to the plant. There will also be all the buildings, foundations, ancillary systems, control systems, and electrical infrastructure to support these systems.

Modularization of these types of systems is fairly standard for industrial sites to minimize costs at site. There are several modularization yards in Western Canada that can build construction modules and engineering firms that make this a standard part of their design and construction methodologies. Examples of modularization that could be used for this application are:

- Buildings
- Water Treatment
- E-Houses
- Piping assemblies
- Heat exchangers

- Control rooms.

Modularization must consider the ease of integration, availability of fabrication sites, and the transportation to site. Roads, bridges, and overhead utilities all need to be considered. However, it is normal procedure to send large assemblies to SAGD sites, so it is not anticipated that this will be a significant issue.

13.6 Lessons Learned from the Nuclear Industry

Nuclear projects are complex, and their execution requires a high level of expertise, planning, and coordination. Here are some lessons learned on the execution of nuclear projects:

- Effective project management is critical: nuclear projects require extensive planning, scheduling, and risk management. Effective project management is essential to ensure that the project is completed on time, within budget, and to the required quality standards.
- Safety is paramount: Safety is the most important aspect of nuclear projects. Nuclear power plants are designed with multiple safety features to prevent accidents and mitigate the consequences of any incidents. Safety protocols must be followed rigorously throughout the project lifecycle.
- Regulatory compliance is crucial: nuclear projects are subject to strict regulations and licensing requirements. Failure to comply with these regulations can lead to significant delays and cost overruns. Regulatory compliance should be considered from the initial planning stages of the project.
- Indigenous and community engagement is essential: nuclear projects can have significant impacts on Indigenous partners, local communities, the environment, and the economy. Effective engagement is essential to build trust and ensure that all parties are informed and involved in the project.
- Technology selection is critical: The selection of appropriate technology is critical for the success of nuclear projects. The chosen technology must be safe, reliable, and cost-effective. The technology should be chosen based on the specific requirements of the project and its operational context.
- Training and knowledge transfer are important: nuclear projects require a high level of expertise and specialized knowledge. It is important to ensure that the necessary training is provided to the project team and that knowledge transfer takes place to enable effective operation and maintenance of the nuclear facility.
- Proper financing is necessary: nuclear projects are capital-intensive, and financing is a critical component of the project. A sound financial plan should be developed to ensure that the project is adequately funded throughout its lifecycle.
- Lessons learned should be documented and shared: nuclear projects are complex and require extensive collaboration between different stakeholders. Lessons learned should

be documented and shared to ensure that best practices are identified and implemented in future projects.

- Overall, the execution of nuclear projects requires a careful and coordinated approach, with a focus on safety, compliance, Indigenous and community engagement, and effective project management.

14. Full Lifecycle Planning

14.1 High Level Plans for Fuel Supply Chain and Logistics

14.1.1 Nuclear Fuel Cycle

The nuclear fuel cycle refers to the set of processes and operations that uranium undergoes in preparation for use in nuclear power generation.

The cycle begins with the exploration and extraction of uranium ore from a mine that is broadly located throughout the world, with Kazakhstan, Namibia, Canada, and Australia being the major producer countries. Uranium is found in many different places around the world, and over 4 billion tonnes of uranium exist as dissolved particles in the ocean. The uranium concentration in the ocean is kept constant as the chemical reaction of water with uranium-containing rocks (which contain 100 trillion tons of uranium) maintains an equilibrium. It is impossible for humans to extract enough uranium to lower the overall seawater concentrations of uranium, even if nuclear provided 100% of energy worldwide and humans existed for a billion years. Once extracted, uranium ore is typically refined into a uranium concentrate referred to as uranium oxide (U_3O_8) and then converted into uranium hexafluoride (UF_6) gas at a conversion facility.

Naturally occurring uranium consists of three isotopes: U-238 (99.27%), U-235 (0.711%), and a trace amount of U-234. Out of the three isotopes, U-235 is used for energy production in most nuclear reactors as it is a fissile material - a material capable of sustaining a nuclear fission chain reaction in the presence of moderating materials (e.g., water, graphite, etc.). The majority of nuclear reactors in the world require enriched uranium, meaning that the amount of U-235 present in the fuel is higher than in natural uranium. Enrichment refers to the process of increasing the amount of U-235 found in uranium to make it more suitable for use in a nuclear reactor. Since U-235 and U-238 are chemically the same material, a physical separation method (e.g., centrifuge or diffusion) is used to change the isotopic composition of uranium.

The level of enrichment for nuclear power depends on the type of reactor and the specific requirements of the nuclear power plant operator (e.g., cycle length). However, there are limits on the enrichment levels for fuel used set by the International Atomic Energy Agency (IAEA); a 19.9% enrichment level (High Assay Low Enriched Uranium or HALEU) represents the upper limit for civilian applications in the power market.

Following conversion, the UF_6 is sent to an enrichment plant to produce U-235 enriched UF_6. Once enriched, it is ready to be fabricated into nuclear fuel at a nuclear fuel fabrication facility. The UF_6 is de-converted to uranium dioxide powder (UO_2) which is then shaped, sintered, and machined to the appropriate form for a given reactor technology. The pellets or particles are then placed in a neutron-transparent matrix (zirconium-based fuel assembly/bundle or graphite-based pebble or prismatic blocks).

As of 2022, 33 countries operate 441 reactors with a total net electrical capacity of ~393.6 GWe. These reactors require about 74,000 tonnes of natural UO_2 concentrate, which contain ~62,500 tonnes of uranium from mines each year. Further, each GWe of increased capacity will require about 150 tonnes of natural uranium per year of additional mine production. (Note: the amount of fuel in a reactor is much lower due to enrichment).

Current reactor fuel requirements are met through primary supply and secondary sources, including commercial stockpiles, reprocessed used fuel, and some re-enrichment of depleted uranium trails. However, fuel forms for advanced reactors require additional consideration, in particular addressing HALEU fuel availability.

14.1.2 Fuel Availability: HALEU for Advanced Reactors

HALEU is enriched to between 5 and 20% and is required by most of the advanced reactor designs. Historically HALEU fuel has been produced in Russia. It is unlikely that Russia will be a reliable supplier of nuclear fuel for any conceivable time in the future. It is therefore very important that a domestic supply of HALEU fuel be developed.

The US Department of Energy (DoE) is assisting in developing the HALEU supply chain in the United States. Centrus Energy is a US company that is currently developing as a supplier of HALEU fuel. Centrus has completed construction and initial testing of their HALEU Demonstration Cascade and expects to begin production by the end of 2023. The Demonstration Cascade will produce 900 kg of fuel per year. The company goal is to produce a full-scale production facility that would produce 6 tonnes of HALEU per year.

Other suppliers that are participating in the plan to increase HALEU production include Orano, Global Laser Enrichment, and Urenco. It is anticipated that the demand for HALEU will be 40 tonnes/year by the end of the decade. In the short-term, the DoE is looking at manufacturing HALEU by down blending highly enriched uranium from US government stockpiles.

14.2 Conceptual Assessment of Transportation Logistics for SMR Loads to Site

The core components of the small modular reactors are relatively small compared to similarly sized thermal units. It is possible for the major components to travel as individual loads from the manufacturing facilities to the construction site in Alberta. The primary loads would be:

- Reactor Core
- Heat Exchangers
- Turbines

- Transformers
- Electrical Buildings
- Building subsystems.

Moving large loads to industrial sites in Alberta is well proven and there are well established corridors to manufacturing hubs throughout North America.

14.3 Waste Management

The classifications of nuclear waste vary from country to country; however, many member states of the International Atomic Energy Agency (IAEA) have chosen to adopt the classification scheme provided by the IAEA. In the *Classification of Radioactive Waste*, the IAEA states that there are six classes of waste[108]:

1. **Exempt Waste (EW):** This classification of waste refers to waste that meets the criteria for exemption or exclusion from regulatory control for radiation protection purposes.
2. **Very Short-Lived Waste (VSLW):** Waste that can be stored for decay over a limited period of up to a few years and subsequently cleared from regulatory control according to arrangements approved by the regulatory body. VSLW includes waste that contains radionuclides with very short half-lives that are often used for research and medical purposes.
3. **Very Low-Level Waste (VLLW):** This classification refers to waste that does not necessarily meet the criteria of EW, but that does not need a high level of containment and isolation and, therefore, is suitable for disposal in near-surface landfill-type facilities with limited regulatory control. Typical waste in this class includes soil and rubble with low levels of activity concentration.
4. **Low-Level Waste (LLW):** Waste that is above clearance levels but with limited amounts of long-lived radionuclides. This waste requires robust isolation and containment for periods of up to a few hundred years and is suitable for disposal in engineered near-surface facilities.
5. **Intermediate Level Waste (ILW):** Waste that, because of its content, requires a greater degree of containment and isolation than that provided by near-surface disposal. ILW requires no provision, or only limited provision, for heat dissipation during its storage and disposal. Waste in this class requires disposal at greater depths, of the order of tens of meters to a few hundred meters.
6. **High-Level Waste (HLW):** Waste with levels of activity concentration high enough to generate significant quantities of heat by the radioactive decay process or waste with large amounts of long-lived radionuclides that need to be considered in the design of a disposal facility for such waste. In some countries, spent fuel is considered to be HLW.

[108] International Atomic Energy Agency, “Classification of Radioactive Waste”, https://www-pub.iaea.org/MTCD/Publications/PDF/Pub1419_web.pdf.

Figure 14-1 below shows a conceptual illustration for the classification of waste through the activity content and the half-life of the radionuclides contained in the waste. With respect to radioactive waste safety, a radionuclide whose half-life is less than ~30 years is considered to be short-lived. The IAEA stresses that a distinction between waste containing short-lived radionuclides and long-lived ones should be made as the radiological hazards associated with short-lived radionuclides significantly reduce over a few hundred years due to radioactive decay.

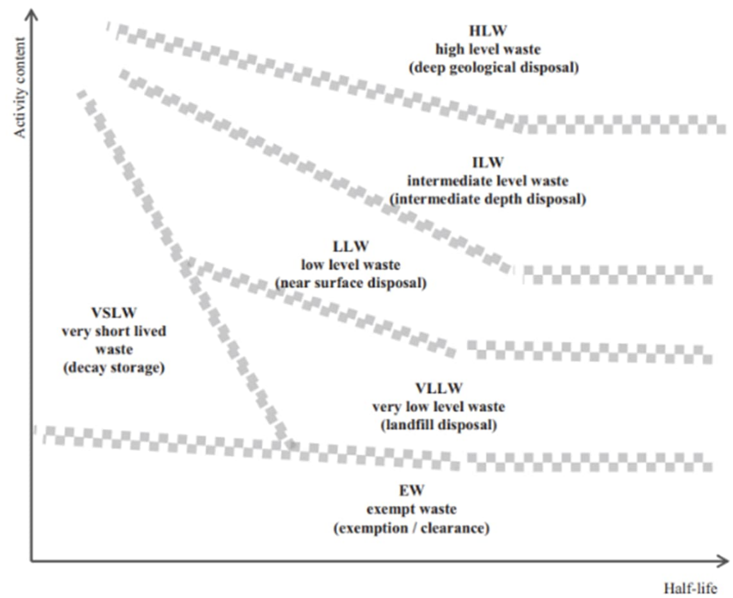


Figure 14-1: Conceptual Illustration of the Classifications of Waste

Not all countries follow the proposed classifications from the IAEA. For instance, Canada classifies its nuclear waste into three categories (LLW, ILW, and HLW) instead of the proposed six. In Canada, low-level waste typically includes personal protection equipment (PPE), mops, boots, gloves, etc., that are used by the nuclear power operating staff during routine operations. Intermediate-level waste typically includes filters, resins, nuclear reactor components, heat exchangers, etc., that are activated by neutrons close to the reactor core. High-level waste typically includes only spent fuel and related fuel assemblies.

In radioactive waste management, materials are presumed to be hazardous until proven to be safe beyond a reasonable doubt. If data is not available to prove that waste should be handled, treated, and disposed of through methods aligned with a lower level of waste classification, higher waste classification methods are used by default. Specific types and properties of radioactive waste should also be considered during radioactive waste management activities. It is also important to note that while heat generation is a characteristic of HLW, other wastes may also generate heat at lower levels. As a result, heat removal should be considered during any radioactive waste management activities.

In Canada, the long-term liability for high-level (fuel) waste disposal and management is held by the Nuclear Waste Management Organization (NWMO). The NWMO was established in 2002 by Canada's nuclear electricity producers in accordance with the Nuclear Fuel Waste Act. The NWMO is responsible for designing and implementing Canada's plan for the long-term management of used nuclear fuel. To fund the NWMO, a small fee is collected and deposited into a spent fuel management fund when nuclear energy is sold. Annual deposits from these spent fuel management funds are then made to the NWMO to fund disposal of the spent fuel. Paying for the long-term management of used nuclear fuel is a relatively small portion of the cost of electricity at approximately 0.1 cent per kilowatt hour of electricity produced.[109]

As no SMRs currently under development are proposing to use the CANDU fuel design, there is currently no finalized plan between prospective SMR licensees and the NWMO for the long-term management of spent fuel or high-level waste generated by SMRs. It is expected that this will be resolved as the market for SMRs matures.

For low and intermediate-level waste, the liability and financial obligation for management and disposal currently lies with the nuclear licensees (operators). However, the NWMO has recently submitted recommendations for an Integrated Strategy for Radioactive Waste that would transfer all intermediate- and high-level waste ownership to the NWMO for their management. Low-level waste would continue to be managed by waste generators and waste owners to either develop their own near-surface disposal facility or engaged other third parties such as EnergySolutions in the United States to accept and handle their low-level waste.

In summary, there will be a solution and final destinations for all types of nuclear waste generated by an SMR facility; however, some of the details are still under development given some of the new waste streams anticipated to be generated by SMR deployment. While the cost for waste management and disposal is typically included in levelized-cost-of-energy calculations, exact values are as of yet unknown, and assumptions based on the current practice of operating nuclear power plants are typically adopted.

14.4 Decommissioning

Decommissioning is a normal part of a nuclear facility's lifetime and needs to be considered at the earliest stages of its development. As part of a facility's initial authorization, a decommissioning plan is developed that demonstrates the feasibility of decommissioning and provides assurance that provisions are in place to cover the associated costs. At the final shutdown, a final decommissioning plan is prepared that describes in detail the decommissioning strategy, how the facility will be safely dismantled, how radiation protection of workers and the public is ensured, how environmental impacts are addressed, how

[109] Canada's plan for the safe long-term management of used nuclear fuel, 2023 (nwmo.ca) https://www.nwmo.ca/~/media/Site/Files/PDFs/2023/03/30/18/42/Backgrounder-2023--Funding-Canadas-plan-for-the-safe-longterm-management-of-used-nuclear-fuel--EN.ashx?la=en.

materials – radioactive and non-radioactive – are to be managed, and how the regulatory authorization for the facility and site are to be terminated.

In Canada, the decommissioning of a nuclear power plant is an activity that requires a CNSC licence (Licence to Decommission). When a new nuclear project starts, a preliminary decommissioning plan must be prepared and submitted to the CSNC as a part of the licensing process.

Regulatory document REGDOC-2.11, *Framework for Radioactive Waste Management and Decommissioning in Canada*, provides an overview on the governance and regulatory framework for radioactive waste management and decommissioning in Canada. REGDOC-2.11.2*, Decommissioning*, sets out requirements and guidance regarding the planning and preparation for as well as the execution and completion of decommissioning.

Once the operator submits a licence application to carry out decommissioning activities, it will be evaluated to determine if an environmental assessment (EA) is required. An EA will determine if there are any significant effects on human health and the environment. Along with the licensing process under the *Nuclear Safety and Control Act*, this will ensure any decommissioning activities are carried out safely to ensure the protection of the workers, the public and the environment. If the EA is approved, the CNSC can then consider the operator's licence application for decommissioning. The hearing process for the EA and issuance of the decommissioning licence will offer opportunities for public input.

To ensure that a project proponent can ultimately fulfil their obligation to decommission the power plant once built, a financial guarantee of decommissioning funds is required before the project can start. This typically takes the form of insurance at the beginning of a project which is replaced by a decommissioning fund during operations as some portion of revenue from energy sales is set aside for future decommissioning. Currently, it is assumed that any SMR development will be required to provide a financial guarantee to decommission the plant before the project can start which increases the initial capital cost of the nuclear power project.

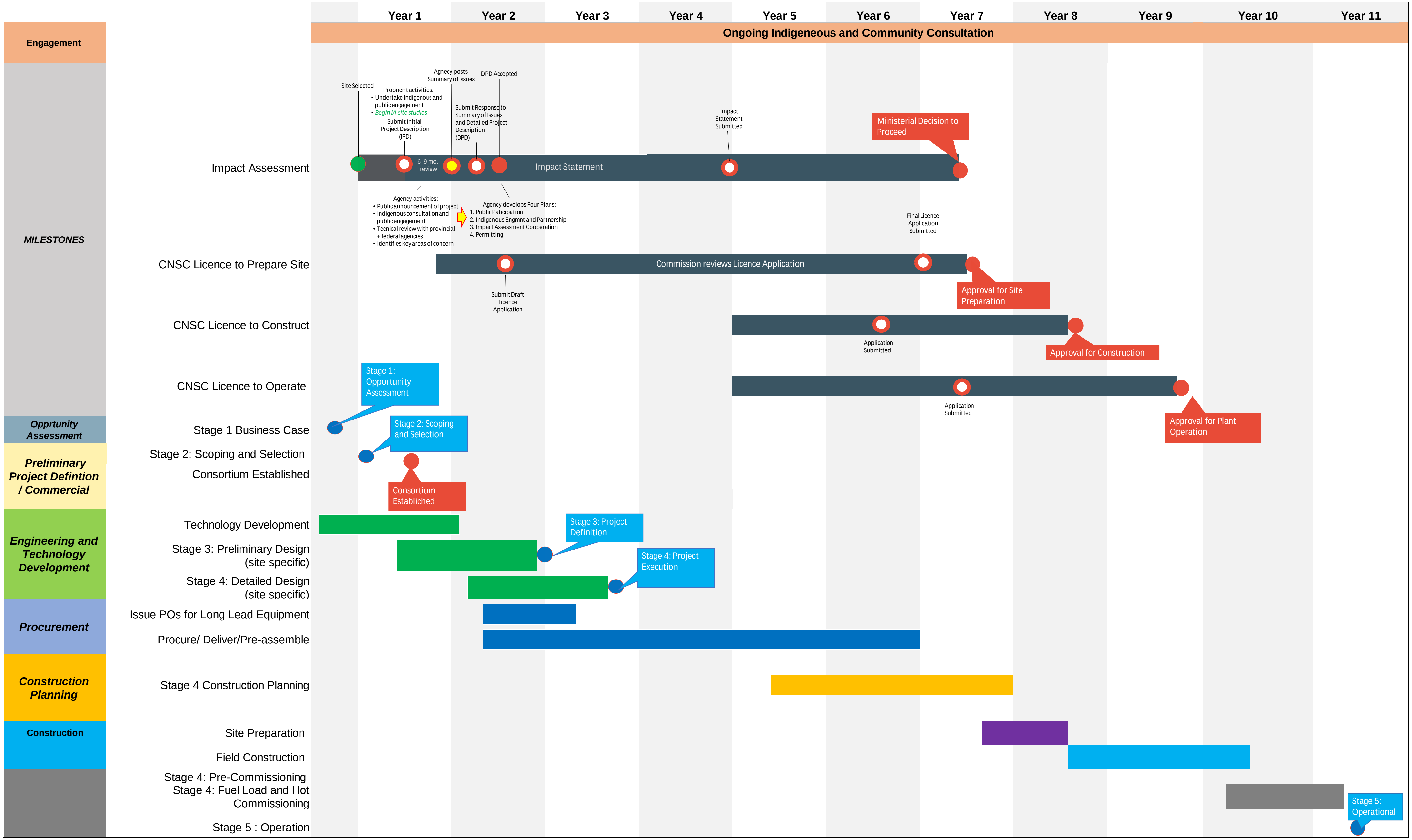
15. Level 1 Schedule

The deployment of a new nuclear technology, in a new to nuclear jurisdiction, is a significant undertaking. As a Class 1A Power Reactor facility, any SMR deployed to support SAGD operations would require licensing by the Canadian Nuclear Safety Commission under Canada's nuclear regulatory framework. Furthermore, based on the assumed size of the SMR facility (in terms of thermal output), the project would require a federal Impact Assessment. In parallel and in support of these activities, project specific developments in terms of site assessments, adapting the SMR design for the selected site, and the design of the interfacing facility are required.

A high-level schedule for the potential SMR project is shown below. This schedule provides an overview of the project life cycle from project initiation through to commissioning and operations. The baseline assumption for early deployment of an SMR for SAGD applications is that an existing nuclear operator would support the operation of the facility. With this assumption in place, there is still significant uncertainty in many of the timelines, some of which are discussed below.

- The actual regulatory timelines for the required licences, i.e., licence for site preparation, construction, and operation.
- The SMR technology selected for deployment and the associated engineering and technology development requirements.
- The site selection and engagement process.
- Supply chain constraints for long-lead items and nuclear fuel

In viewing the schedule, note that the provided timelines have been assembled based on best estimates and may reflect best-case scenarios in execution. There is still significant uncertainty in how the Alberta provincial processes will look for nuclear power development.


Year 1
Year 2
Year 3
Year 4
Year 5
Year 6
Year 7
Year 8
Year 9
Year 10
Year 11
Engagement
Ongoing Indigeneous and Community Consultation
MILESTONES
Impact Assessment
Site Selected
Propnent activities:
• Undertake Indigenous and public engagement
• Begin IA site studies
Submit Initial Project Description (IPD)
Agnecy posts Summary of Issues
DPD Accepted
Submit Response to Summary of Issues and Detailed Project Description (DPD)
6 -9 mo. review
Impact Statement
Impact Statement Submitted
Ministerial Decision to Proceed
Agency activities:
• Public announcement of project
• Indigenous consultation and public engagement
• Tecnical review with provincial + federal agencies
• Identifies key areas of concern
Agency develops Four Plans:
1. Public Paticipation
2. Indigenous Engmnt and Partnership
3. Impact Assessment Cooperation
4. Permitting
CNSC Licence to Prepare Site
Commission reviews Licence Application
Submit Draft Licence Application
Final Licence Application Submitted
Approval for Site Preparation
CNSC Licence to Construct
Application Submitted
Approval for Construction
CNSC Licence to Operate
Application Submitted
Approval for Plant Operation
Stage 1: Opportunity Assessment
Opprtunity Assessment
Stage 1 Business Case
Stage 2: Scoping and Selection
Preliminary Project Defintion / Commercial
Stage 2: Scoping and Selection
Consortium Established
Consortium Established
Engineering and Technology Development
Technology Development
Stage 3: Preliminary Design (site specific)
Stage 3: Project Definition
Stage 4: Detailed Design (site specific)
Stage 4: Project Execution
Procurement
Issue POs for Long Lead Equipment
Procure/ Deliver/Pre-assemble
Construction Planning
Stage 4 Construction Planning
Construction
Site Preparation
Field Construction
Stage 4: Pre-Commissioning
Stage 4: Fuel Load and Hot Commissioning
Stage 5 : Operation
Stage 5: Operational

16. Project Financials

The major input to the economic impact of building an SMR in Alberta is the Capital Expenditure (CAPEX) to build the facility. The CAPEX is made up of the Nuclear Island equipment costs, the non-nuclear integration with the SAGD plant, and any additional infrastructure costs required to build the facility and provide access, security, and maintenance infrastructure. In addition to these direct costs, there are the costs for engineering, regulation, procurement, construction, commissioning, start-up, and operation.

This assessment was based on a 400MW thermal nuclear reactor integrated to the generic COSIA SAGD Reference facility, ML-WLS-OSTG. The SMR generates steam which is used to replace the steam generation of the generic facility.

The costs are intended to be representative of a generic SAGD integration with an SMR based on the COSIA representative facility. Actual implementation costs will vary based on:

- The SMR technology selected to be deployed.
- The location of the facility.
- The size of the facility.
- Whether the technology implemented widely or is FOAK/near FOAK deployment.
- The configuration of interfacing facility including requirements (if any) for thermal heat storage.
- The relationship between the SAGD site owner and any other parties involved in the SMR operation.

The size of the SMR facility used for this assessment was 400 MWth. The costs adopted for this study are as follow:

- CAPEX[110]: $1.5 Billion to $4.5 Billion ($3.0 Billion was adopted for the economic impact assessment).
- OPEX: $32.5 Million to $97.5 Million per annum.

Note that these CAPEX and OPEX values are provided as technology-agnostic, representative values and may not be reflective of the actual costs of SMR deployment at SAGD facility.

[110] Based on similar publicly available sources.

17. Economic Impact Assessment

The commercial development of an SMR for use in the oil sands will support significant economic benefits locally for Alberta and nationally as the spending ripples through the Canadian economy.

This section identifies and estimates the economic impacts that will be supported by deployment of SMR at SAGD facility during the following phases (Figure 17-1):

- Upfront design and construction of a generic 400 MWth SMR for use in the oil sands. This includes the design and engineering of the plant and the direct on-site construction activity and purchase of specialty equipment and materials as well as the commissioning of the plant to begin commercial operations.
- Ongoing annual operations of the plant over its design life.

All dollar values reported throughout the report are in 2023$ prices and are undiscounted unless otherwise noted. Refer to Appendix J for additional on the economic impact assessment model.

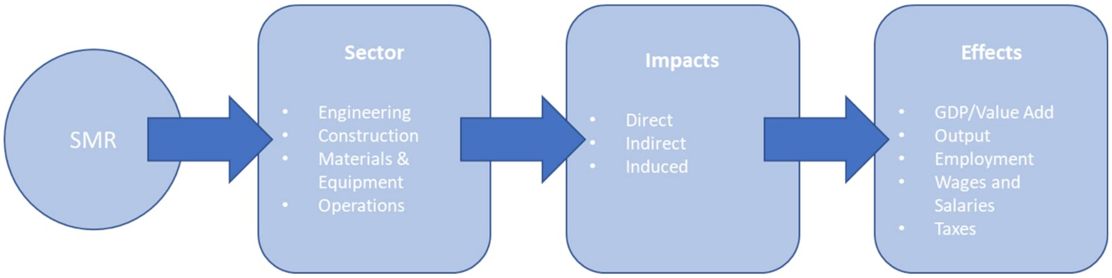
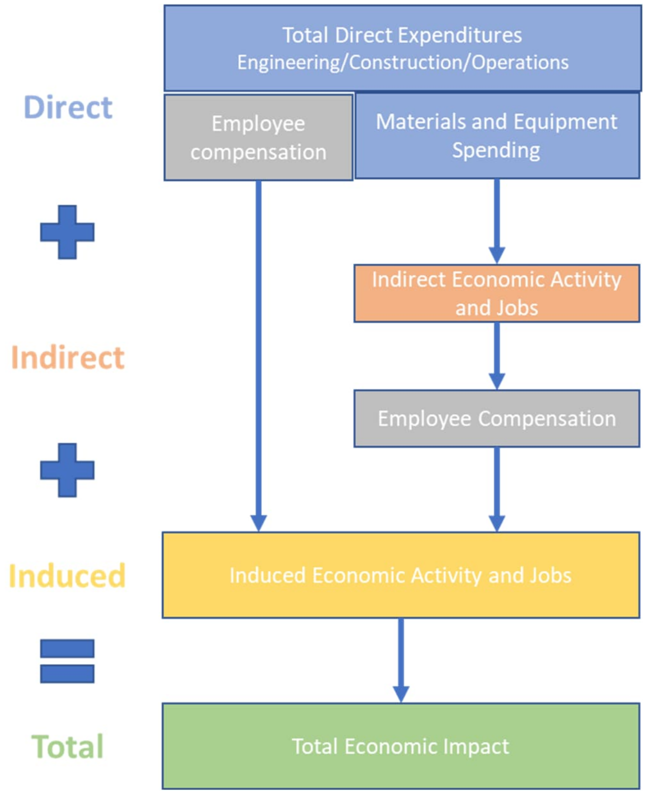


Figure 17-1: Framework for Assessing the Economic Impact of an SMR

The economic impacts of an SMR will occur at the following levels:



- **Direct Impacts** – The economic activity and employment associated with the SMRs themselves. During the construction period this includes the on-site construction labour, as well as the impacts associated with design and engineering of the plant, construction management, and commissioning of the plant. During the annual operations this includes the impacts associated with operations and maintenance of the plant.
- **Indirect Impacts** – The economic activity and employment supported via the supply chain purchase of materials and equipment from Alberta and Canadian-based suppliers. During the construction period, this includes the spending on the materials and equipment needed to construct the plant, such as steel, concrete, pumps, tanks, turbines, and electrical transformers. During the annual operations of the plant, this includes the spending on fuel, replacement parts and equipment as well as other supplies needed to operate the plant.
- **Induced Impacts** – The economic activity and employment supported by those directly or indirectly employed in the construction and operations of the plant spending their incomes on goods and services in the wider Alberta and Canadian economies. This spending helps to support jobs in the industries that supply these purchases and includes jobs in real estate, retail, and companies producing a variety of consumer goods and services.

To estimate the economic impacts of an SMR, we developed a customized economic impact model using detailed input-output data from Statistics Canada for both the Alberta and national economies.[111] We used the model to estimate the following economic impacts:

- Gross Domestic Product (GDP) – all references to GDP in this report are to GDP at "basic prices" also known as gross value add or GVA.
  - Employment
  - Wages and salaries
  - Select taxes.

17.1 Construction

We estimate that the construction of a 400 MWth generic SMR for use in the oil sands will generate $ 3.0 Billion (+/- 50%) of total capital expenditures[112] (Note: For economic impact assessment $3.0 Billion for a 400MWth SMR facility was used). This includes project management and direct construction labour, spending on materials, such as concrete and structural steel, and spending on specialty equipment, such as the reactor vessel and core, pumps, and turbines, indirect construction support and inspections and commissioning. Not all spending will occur within Alberta or Canada.

Alberta has a very strong industrial economy in terms of manufacturing, construction as well as oil and gas, and mining. These industries have been successful in delivering complex mega projects in adjacent sectors, such as mining and oil and gas. Given the fact that many of the aspects associated with the conventional island draw synergies and adjacencies from these sectors. Industries within Alberta are likely well positioned to support many aspects of a new SMR build, including site infrastructure, buildings, structures, and balance of plant equipment. However, many of the manufacturers in Alberta lack the requisite certifications, which means that many of the components associated with nuclear island will need to be imported from elsewhere in Canada and internationally.

The economic impacts associated with the equipment manufactured outside of the region is excluded from the economic impact modeling because it does not generate impacts within in the province. However, a portion of this equipment spending, namely the wholesale and transportation margins should be included in the economic impact modelling. To estimate the wholesale and transportation margins that would accrue to businesses located in the province, we used data from the input-output tables for Alberta to estimate the portion of the equipment spending that is spent in the wholesale and transportation sectors.

All told, we estimate that $1,561.1 million of construction period spending will occur within the province. This amounts to **51% of the construction spending** (labor, material, and equipment) (Figure 17-2). This spending will generate significant impacts that will ripple

[111] Please see Appendix J for additional details on the models.
[112] The capital cost estimates are based on average cost of $7.1 million per MWth.

through the Alberta economy. An additional $973 million (31%) will occur at other Canadian firms located outside of Alberta. The remaining spending will be with international suppliers.

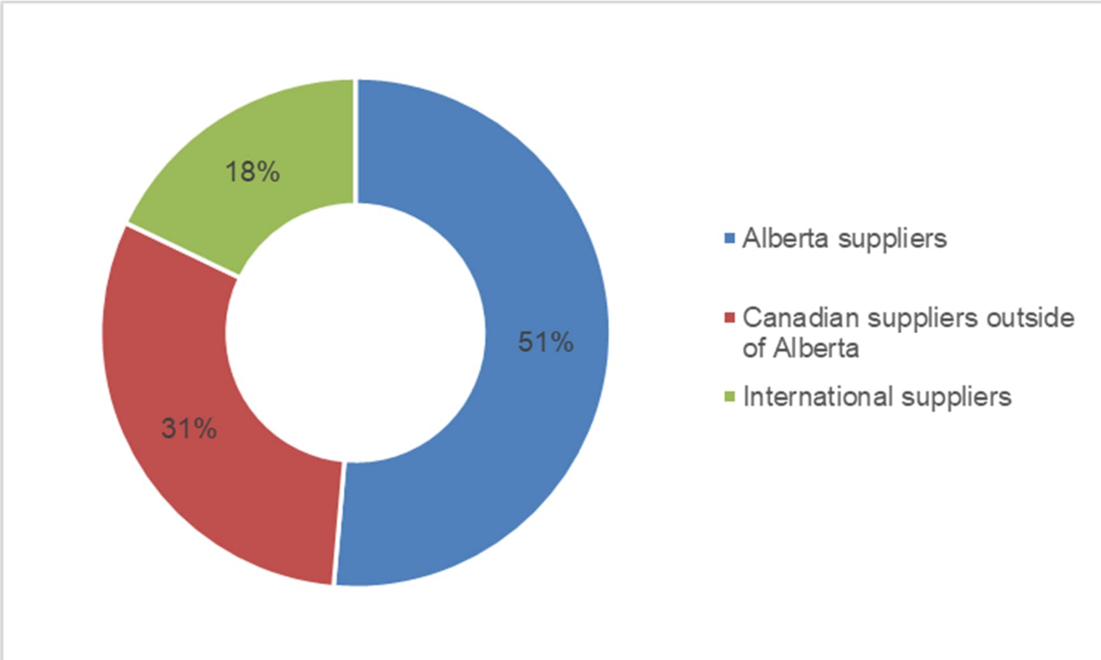


Figure 17-2: Geographic Distribution of Construction Spending

The construction of an SMR will generate over $3.4 billion in total GDP for the Alberta economy, including over $2.1 billion of direct, nearly $700 million of indirect, and nearly $642 million of induced GDP within the province (Table 17-1). In addition to the 7,336 direct job-years at the site, the project will support 4,885 indirect job-years and 5,650 induced job-years for a total employment impact of nearly 17,870 total job-years within the province. This amounts to an average of 1,834 direct, 1,121 indirect, and 1,412 induced jobs per annum over the four-year construction period. The project will also support nearly $1.5 billion in total wages and salaries within the province.

Within the Canadian economy, the construction of the plant will generate a one-time GDP impact of over $4.7 billion, including over $2,142 million of direct GDP, $1,388 million of indirect GDP, and $1,236 million in induced GDP (Table 17-1). This will support 7,336 direct job-years, over 9,600 indirect job-years and 6,950 induced job-years for a total employment impact of nearly 23,920 total job-years. This amounts to an average employment impact of 1,834 direct jobs, 2,400 indirect jobs, and nearly 1,737 induced jobs per annum over the four-year construction period. The employment impacts will support $1.8 billion in total wages and salaries.

Table 17-1: Construction Period Economic Impacts

	Total		Average Annual[113]	
	Alberta	**Canada**	**Alberta**	**Canada**
GDP (Millions $)				
Direct	$2,142.0	$2,142.0	$535.5	$535.5
Indirect	$699.5	$1,388.8	$174.9	$347.2
Induced	$642.0	$1,236.1	$160.5	$309.0
Total	$3,483.4	$4,766.9	$870.9	$1,191.7
Employment (job-years)				
Direct	7,336	7,336	1,834	1,834
Indirect	4,885	9,634	1,221	2,409
Induced	5,650	6,950	1,413	1,738
Total	17,871	23,920	4,468	5,980
Wages and Salaries (Millions $)				
Direct	$858.2	$858.2	$214.6	$214.6
Indirect	$371.0	$783.7	$92.8	$195.9
Induced	$275.1	$253.0	$68.8	$63.3
Total	$1,504.3	$1,894.9	$376.1	$473.7

The economic impacts generated by the construction of the plant within the province will generate nearly $232 million in fiscal impacts (an average of nearly $58.0 million per year) for the provincial and national governments. The economic impacts that will be generated within the Canadian economy will generate over $367.5 million in total tax impacts, an average of nearly $94.1 million per year (Table 17-2).

Table 17-2: Construction period fiscal impacts ($ Millions)

	Total		Average Annual[114]	
	Alberta	**Canada**	**Alberta**	**Canada**
Taxes on production ($)	$85.6	$124.3	$21.4	$31.0
Taxes on products ($)	$18.4	$85.8	$4.6	$21.5
Federal ($)	$11.9	$64.2	$2.9	$16.1
Provincial ($)	$6.5	$21.7	$1.6	$5.4
Corporate income taxes ($)	$52.9	$63.2	$13.2	$15.8
Federal income taxes ($)	$35.2	$44.0	$8.8	$11.0

[113] We assume that the construction spending will occur over the four-year period. The average annual impacts were calculated by dividing the total impacts by 4.
[114] The construction spending will occur over the four-year period. The average annual impacts were calculated by dividing the total impacts by 4.

	Total		Average Annual[114]	
	Alberta	Canada	Alberta	Canada
Provincial income taxes ($)	$23.1	$28.8	$5.8	$7.2
Federal payroll taxes ($)	$17.3	$21.6	$4.3	$5.4
Total taxes ($)	$232.4	$367.8	$58.1	$91.9

17.2 Annual Operations

Once fully operational, the plant will generate 400 MW of thermal output. The plant will directly employ 246 individuals and support nearly $37.9 million in direct wages and salaries. For the purposes of this analysis, It is assumed that all the employees will live in Alberta.

In addition to the $37.9 million in wages and salaries, the annual operations of the plant will generate $11.8 million in materials and equipment spending, this includes spending on spare parts, replacement equipment, and other expenses. The plant will also require $22.1 million in fuel related spending.

All told, it is estimate that the operations of the plant will generate $71.9 million in average annual spending - 62% ($44.6 million) will occur within Alberta and an additional 22% at other Canadian suppliers located outside of Alberta, resulting in 84% of the operations spending occurring within Canada. The remaining 16% of spending will be at suppliers located outside of Canada (Figure 17-3).

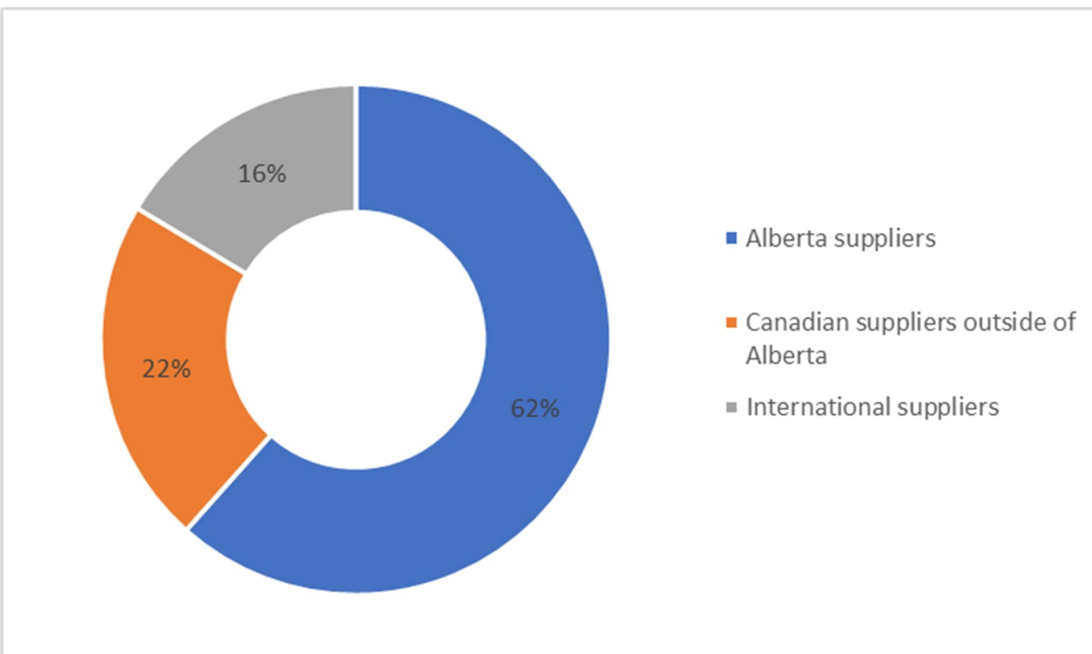


Figure 17-3: Geographic Distribution of Operations Spending

The annual operations of the SMR will generate an average of $131.2 million in total GDP for the Alberta economy. including nearly $100.6 million of direct, $7.0 million of indirect, and $23.6 million of induced GDP (Table 17-3). Over the 60-year operating life of the plant, the plant will generate over $7.8 billion in total GDP impacts (undiscounted).

In addition to the 246 employees who will work at the plant, the annual operations will support 47 indirect jobs and 208 induced jobs for a total employment impact of 501 total jobs within Alberta. The project will also support $48.1 million in total wages and salaries within the province per annum. Over the operating life of the plant, the plant will support over $2.8 billion in total wages and salaries (undiscounted).

Within the Canadian economy, the annual operations of the plant will generate $154.6 million in total GDP, including $100.6 million of direct GDP, $17.5 million of indirect GDP, and over $36.5 million in induced GDP (Table 17-3). All told, the operations of the plant will generate nearly $9.3 billion in total GDP impacts over the operating life of the plant (undiscounted).

The annual operations will support 95 indirect jobs and 205 induced jobs, which along with the 246 direct jobs, amount to a total average annual employment impact of 547 total jobs within Canada. The employment impacts will support an average of $56.2 million in total wages and salaries per annum and nearly $3.4 billion over the operating life of the plant (undiscounted).

Table 17-3: Operations Economic Impacts

	Total		Lifetime[115]	
	Alberta	**Canada**	**Alberta**	**Canada**
GDP (Millions $)				
Direct	$100.6	$100.6	$6,035.0	$6,035.0
Indirect	$7.0	$17.5	$421.7	$1,048.5
Induced	$23.6	$36.5	$1,417.9	$2,192.7
Total	$131.2	$154.6	$7,874.7	$9,276.2
Employment (job-years)				
Direct	246	246	14,784	14,784
Indirect	47	95	2,793	5,693
Induced	208	205	12,480	12,328
Total	501	547	30,056	32,804
Wages and Salaries (Millions $)				
Direct	$34.1	$37.9	$2,046.1	$2,273.4
Indirect	$3.3	$7.7	$195.2	$460.3
Induced	$10.8	$10.7	$646.8	$640.9
Total	$48.1	$56.2	$2,888.0	$3,374.7

115 The total lifetime impacts of the operations of the plant were calculated by multiplying the annual impacts by the 56-year operating life of the plant.

The economic activity generated by the annual operations of the plant within the province will generate an average of $20.2 million in fiscal impacts for the provincial and national governments annually. Over the 60-year operating life of the plant, this will amount to $1,213 million in total fiscal impacts (Table 17-4). The economic impacts that will be generated in the Canadian economy will generate an average of $22.7 million in fiscal impacts per annum and $1,360 million over the operating life of the plant.

Table 17-4: Operations Fiscal Impacts (Millions $)

	Total		Lifetime[116]	
	Alberta	Canada	Alberta	Canada
Taxes on production ($)	3.6	3.3	213.8	199.7
Taxes on products ($)	0.7	2.6	41.6	153.0
Federal ($)	0.5	2.0	28.8	119.3
Provincial ($)	0.2	0.6	12.8	33.7
Corporate income taxes ($)	10.3	10.2	616.8	609.3
Federal income taxes ($)	2.6	3.1	158.8	185.6
Provincial income taxes ($)	1.7	2.0	104.0	121.5
Federal payroll taxes ($)	1.3	1.5	78.0	91.1
Total taxes ($)	20.2	22.7	1,213.0	1,360.1

17.3 Economic Impact summary

The direct expenditures, whether resulting from the one-time engineering and construction of the SMR or annual operations, will support significant economic benefits for the economy of Alberta and Canada.

All told the proposed project will support the following economic impacts:

Construction Period

- **51%** of the construction spending (labour, materials, and equipment) will occur within Alberta and **82%** will occur within Canada.
- **$3.1 billion**[117] in total capital spending will support nearly **$3.5 billion** in GDP locally in Alberta and over **$4.8 billion** in Canada.

  This includes **17,870 total job-years** in Alberta, which is an average of **3,467 total jobs per year** over the assumed 4-year construction period and **23,920 total job-years** across Canada, which is an average of **over 5,980 total jobs per year**.
- **$1.5 billion** in total wages and salaries in Alberta and **$1.9 billion** across Canada. The construction period will also support **$368 million** in fiscal impacts across Canada.

116 The construction spending will occur over the four-year period. The average annual impacts were calculated by dividing the total impacts by 4.

117 Construction spending in the range of $2.5 to 3.5 billion (for economic impact assessment $3.0 Billion for a 400MWth SMR facility was used).

Annual Operations

- **62%** of the operations and maintenance spending (labour, materials, and equipment) will occur within Alberta and **84%** will occur within Canada.
- The operations of the facility will generate an average of **$71.9 million** in total spending per annum, which will support **$131.2 million** in total GDP locally in Alberta and **$154.6 million** across Canada annually.
- The facility will directly employ **246** employees. All told the annual operations will support **501 total jobs** in Alberta and **546 total jobs** across Canada.
- The annual operations will support **$37.9 million** in direct wages and salaries and will support **$48.1 million** in total wages and salaries in Alberta and **$56.2 million** across Canada. The operations will also support **$22.7 million** in fiscal impacts across Canada per annum. Hydrogen Production Configuration

18. Hydrogen Production

18.1 Introduction and Background

In this section, the evaluation of select hydrogen production processes is presented and a suggestion is made for the electrolyzer technology best suitable for operation with an SMR.

Hydrogen generation processes fall into three main categories: electrolysis, thermochemical processes, and hybrid thermochemical processes. Electrolysis is the electrically driven transport of an ion or anion through an electrolyte to produce hydrogen and oxygen. Thermochemical processes rely on heat-driven chemical reactions for water splitting using intermediate chemical compounds which are regenerated in the cycle. Finally, hybrid thermochemical processes are a combination of the previous two categories and require heat for chemical reactions and electricity for electrolysis. The advantage of hybrid thermochemical processes is the reduced electrical power demand to generate hydrogen compared to conventional electrolysis.

Hydrogen production processes also differ in the state of reactant water at the input: liquid or steam. There are more hydrogen production processes that use liquid water (e.g., proton exchange membrane (PEM), alkaline water electrolysis (AWE)), but overall separation efficiency typically increases when steam is utilized (e.g., solid oxide electrolytic cell (SOEC)).

Several hydrogen production processes are suitable for coupling with an SMR[118]. For example, the thermal energy produced by a reactor can be used to generate steam and electricity for SOEC or provide thermal heat for thermochemical processes depending on the reactor type and thermochemical process. Furthermore, the electricity generated can be used to power electrolyzers and produce low carbon intensity hydrogen. However, some hydrogen

[118] Verfondern, K. Nuclear energy for hydrogen production. Germany: N. p., 2007.

production methods require high grade heat as input which will not be feasible with some reactor types, or impractical if additional temperature boosting is required.

18.2 Objective

The following hydrogen generating technologies have been assessed in this report:

- Solid oxide electrolytic cell (SOEC).
- Membrane electrolyzers (PEM, anion exchange membrane (AEM), AWE).
- Membrane-free electrolyzers (MFE), and
- Thermochemical hydrogen production (Sulfur Iodine, Cerium Oxide, Copper Chloride).

The technologies were evaluated using a Pugh Matrix with a baseline which considered criteria from performance characteristics to CAPEX/OPEX estimates. From this evaluation, one low-temperature electrolysis technology were selected for the LCOH calculations. The analysis was decoupled from the SMR selection and focused on the hydrogen production technology evaluation.

18.3 Design Basis and Assumptions

18.3.1 Design Basis

18.3.1.1 Nuclear Power Plant and Hydrogen Production Plant Interface

The interactions between the nuclear power plant and the hydrogen production processes are shown in Figure 18-1. The diagram shows the flow of electrical or thermal energy to support each hydrogen production method. Water is also shown as the key input to the process, and hydrogen and oxygen are the net products.

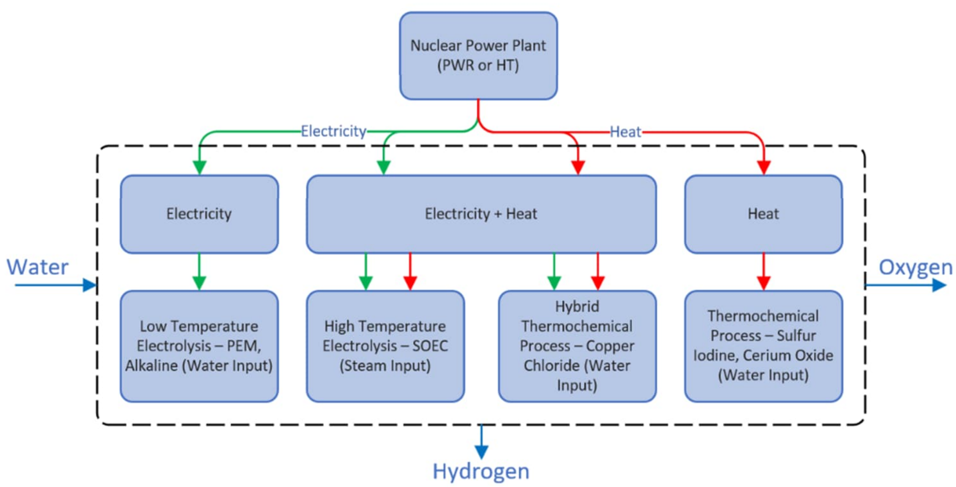


Figure 18-1: Nuclear Power Plant Energy Flow to Hydrogen Production Processes

The block flow diagram in Figure 18-1 is a simplified representation of the interactions between the power plant and the hydrogen generation process. The balance of system (BOS) is not shown explicitly but is assumed to be included within the scope of each hydrogen production technology. The electrical and thermal power demand for the BOS is not shown in the Figure 18-1.

18.3.2 Assumptions and Exclusions

18.3.2.1 Nuclear Power Plant

Assumptions:

- The SMR electrical output provides 100% of the energy to the electrolysis process.
- An SMR is selected with approximately 250 MW of thermal power.
- The SMR thermal energy to electrical energy conversion efficiency is 33%.

Exclusions:

- The analysis does not consider a specific SMR technology as the baseline for electrical and/or thermal power input to the hydrogen production processes.

18.3.2.2 Hydrogen Production

Assumptions:

- The SMR thermal energy output is 250 MWth (maximum) and electrical energy output is 82.5 MWe (maximum).
- Sufficient water or steam at the necessary water quality is available as an input.
- All hydrogen is used and no storage tanks are needed.
- The LCOE ($CAD) is assumed to be between $61/MWe (baseline) to $133/MWe in this study.
- The exchange rate is $1.33 USD/CAD.

Exclusions:

- Hydrogen and oxygen use cases will not be analyzed.
- Location of the hydrogen plant relative to the SMR or other power plant equipment (e.g., centralized, or decentralized layout) will not be analyzed.

18.4 Electrolyzer Technology Evaluation

18.4.1 Technology Overview

18.4.1.1 Proton Exchange Membrane Electrolysis (PEM)

In a PEM electrolyzer an electrical potential is applied across an assembly of cells connected in series – often referred to as a stack – to produce hydrogen and oxygen from water. A single cell is comprised of an anode electrode assembly, a membrane assembly, and a cathode electrode assembly. The membrane allows hydrogen ions to cross between the anode and cathode, and, therefore, no electrolyte solution is necessary. This is sometimes referred to as a solid polymer electrolyte.

Water enters the stack at the anode, and with the application of an electrical potential, hydrogen is formed on the cathode side and oxygen on the anode side. Hydrogen gas may be humid due to water crossover through the membrane. The purity of hydrogen can be improved outside of the stack through a hydrogen dryer/purifier system and the hydrogen pressure may be increased with additional compression stages to ensure compatibility with the downstream process. The oxygen gas is entrained in water flowing through the system and is separated from the water outside of the stack. Similarly, if the oxygen is collected an additional purification step may be added. A schematic view of the PEM electrolyzer cell is presented in Figure 18-2.

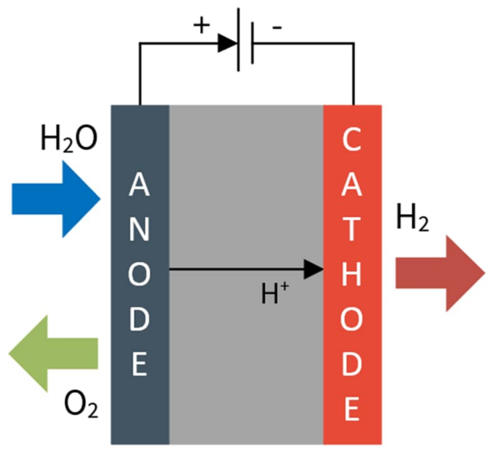


Figure 18-2: Proton Exchange Membrane Electrolyzer Cell Schematic

A notable advantage of PEM electrolyzers is the ability to quickly transition between operating points. This is a preferred characteristic where input power may vary quickly, for example, the output from a renewable energy grid. Another advantage is that only filtered water and electricity are the only inputs to the process. Other hydrogen generation technologies may require the addition of chemicals to allow water splitting to occur. Finally, the electrolyzer assembly has a smaller footprint compared with some other electrolyzer technologies.

Each stack requires replacement at approximately 6–8-year intervals, and this may vary depending on the supplier. Design life of the BOS components is typically 30 years. Typical vendors for PEM electrolyzers include:

- Accelera by Cummins
- Nel
- Ohmium
- Plug Power.

An image of typical PEM electrolyzer assemblies are shown in Figure 18-3. The BOS components included in the system may vary between vendors which impacts the layout and footprint.

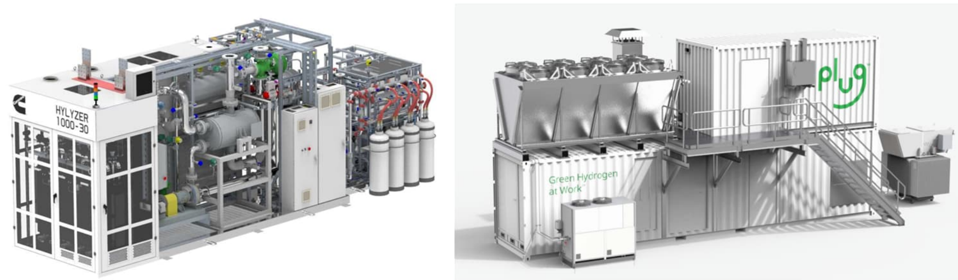


Figure 18-3: Example PEM Electrolyzer Systems from Accelera (Left) and Plug Power (Right)

18.4.1.2 Anion Exchange Membrane Electrolysis (AEM)

Anion Exchange Membrane (AEM) cell construction is similar to PEM, but AEM stacks instead transport hydroxide ions (OH-) across a membrane when an electrical potential is applied. Water enters the cell on the anode side and passes through the membrane. At the cathode side, the water is split. Hydrogen exits the cell at the cathode side while the hydroxide ion is pulled back to the anode side where it forms water and oxygen gas. A schematic view of an AEM electrolyzer cell is presented in Figure 18-4

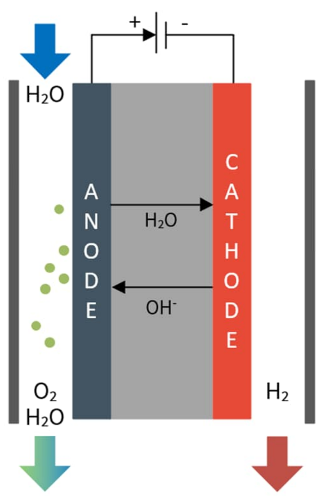


Figure 18-4: AEM Electrolysis Cell Schematic

The membrane material does not utilize rare earth metals which reduces the cost when replaced at regular intervals when compared to PEM electrolysis cells. An electrolyte solution of approximately 1% potassium hydroxide (KOH) is utilized to maintain water conductivity. Hydrogen is produced under pressure of up to 35 bar_g, while the oxygen is maintained around 1 bar_g. The pressure gradient across the membrane reduces the ability for moisture to crossover into the hydrogen side thus reducing the need for downstream hydrogen drying and purification.

AEM electrolyzers are provided by the vendor Enapter. The technology is in the demonstration phase and installations around 1-2MW scale are being announced. An image of an AEM electrolyzer system is shown in Figure 18-5.

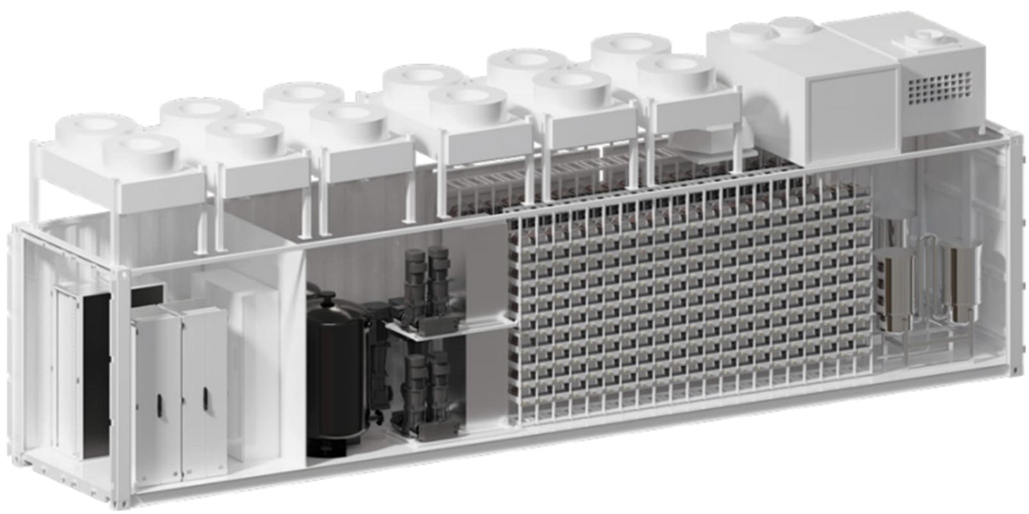


Figure 18-5: Example AEM Electrolyzer System from Enapter

18.4.1.3 Alkaline Water Electrolysis (AWE)

Alkaline water electrolysis operates similarly to PEM electrolysis, but transports hydroxide ions (OH-) instead of hydrogen ions across a porous divider when an electrical potential is applied. Furthermore, AWE utilizes a liquid alkaline solution of sodium hydroxide or potassium hydroxide as the electrolyte. When electricity is applied to the electrodes, hydrogen and oxygen are formed at the cathode and anode, respectively. The hydroxide ion must then travel a short distance to from the cathode to the anode. A schematic of a typical alkaline cell is shown in Figure 18-6.

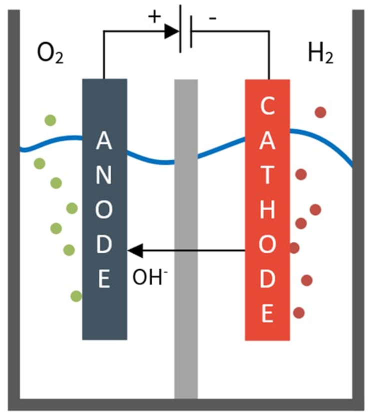


Figure 18-6: Alkaline Water Electrolysis Cell Schematic

Gases formed at the electrodes require separation from the solution before distribution to downstream processes. The purity of hydrogen can be improved outside of the stack through a hydrogen dryer/purifier and the hydrogen pressure may be increased with additional compression stages to ensure compatibility with the downstream process.

AWE technology is a proven technology with a long track record of operation. Currently, the largest electrolyzer in operation is an AWE type electrolyzer with a size of 150 MWe (operated by chemical manufacturer Ningxia Baofeng Energy Group[119]).

In terms of durability, AWE electrolyzers generally require stack replacements after 8 years, which is less frequent than either PEM or electrolyzers. In addition, while the alkaline solution is recycled, it also requires periodic replacement. Typical vendors of AWE electrolyzers include:

- ThyssenKrupp Nucera
- John Cockerill
- Nel
- Sunfire.

An image of an AWE electrolyzer is shown in Figure 18-7. Similar to the packaged PEM electrolyzer, the BOS location and footprint will vary between vendors. Typically, the footprint of an AWE system will be larger than a PEM system.

[119] Scaling Up: Three Low-Carbon Hydrogen Plants Leading the Charge, International Energy Forum, 21 September 2022, Online, https://www.ief.org/news/scaling-up-three-low-carbon-hydrogen-plants-leading-the-charge.

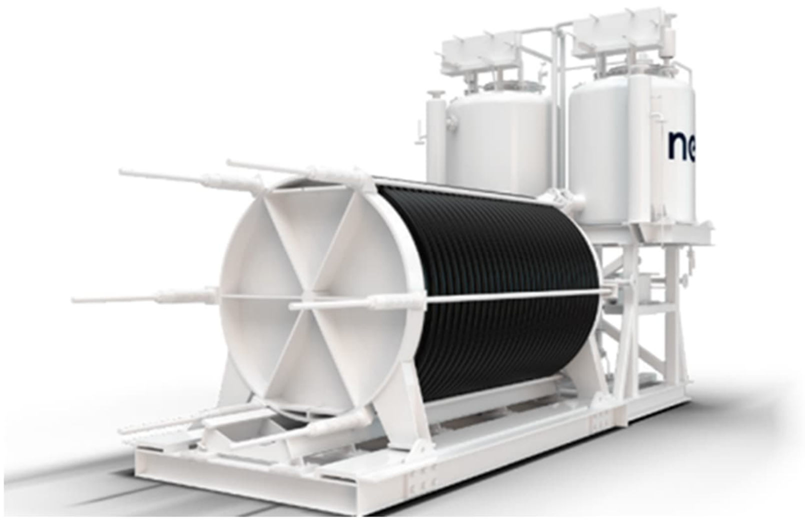


Figure 18-7: Example AWE Electrolyzer System from Nel

18.4.1.4 *Membrane Free Electrolysis (MFE)*

Membrane Free Electrolysis (MFE) electrolyzers are similar in construction to AWE electrolyzers; however, the cell assembly does not include a porous membrane. Without a membrane, the distance between the electrodes must be increased to isolate the hydrogen and oxygen gases. The increased distance also requires a more conductive solution to counteract the resistance between the electrodes. However, removal of the membrane increases the durability of MFE electrolyzers as membrane replacement is not necessary leading to projected lifetimes greater than 12 to 15 years. A typical MFE cell is shown in Figure 18-8.

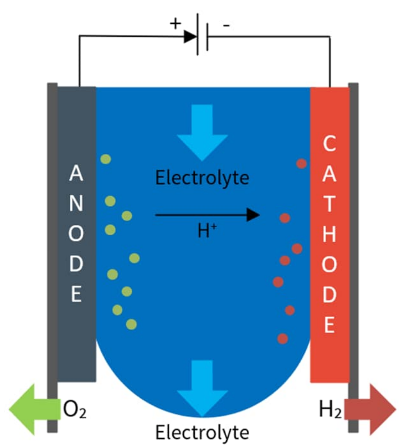


Figure 18-8: Membrane-Free Water Electrolysis Cell Schematic

Currently, there is one commercial vendor offering an MFE system: Clean Power Hydrogen. The technology is innovative with small scale installations planned to be completed in 1 to 2 years. The footprint of an MFE electrolyzer is larger than for other systems discussed due to the need for a gas separation stage separate from the internal solution. A conceptual assembly of a MFE electrolyzer is shown in Figure 18-9.

Figure 18-9: Example MFE Electrolyzer System from Clean Power Hydrogen

18.4.1.5 *Solid Oxide Electrolytic Cell (SOEC)*

Solid Oxide Electrolytic Cell (SOEC) electrolyzers are also referred to as high temperature steam electrolyzers (HTSE) due to the use of steam as feedstock and the water splitting reaction occurring between 500°C to 800°C. The construction of the SOEC cell is most similar to PEM technologies as it uses a solid membrane. In the SOEC the cathode and anode are separated by a ceramic membrane, also known as the solid-oxide electrolyte. Steam is injected into the cathode and with an applied is reduced to hydrogen and oxygen at the cathode-electrolyte interface. The hydrogen gas diffuses and is collected on the cathode side. Meanwhile, the oxygen ions are conducted through the solid electrolyte. At the electrolyte-anode interface, oxygen gas is formed and collected. A schematic of a typical SOEC cell is shown in Figure 18-10.

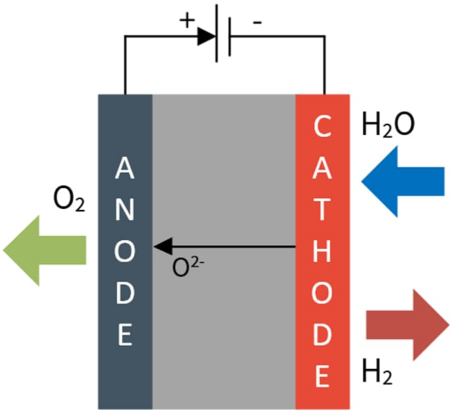


Figure 18-10: Solid Oxide Electrolytic Cell Schematic

An advantage of SOEC electrolyzers is that the high temperature enables increased efficiency via a reduction in electrical power requirements. Another advantage is that precious metals are not required and easily obtained ceramics are used in place of a membrane. Conversely, SOEC electrolyzers have a long start up time due to the high temperature requirements. In addition, the durability of SOEC is not as high as other electrolysis methods, and developments in this area are needed.

The solid oxide electrolyzer technology is considered to be in demonstration phase with a few small-scale projects recently announced and in progress. Examples of SOEC vendors include:

- Bloom
- Sunfire
- Topsoe.

Conceptual models of the SOEC systems are shown in Figure 18-11.

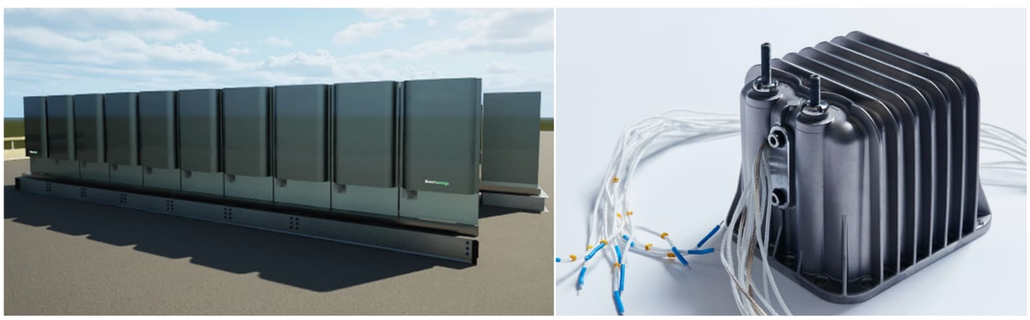


Figure 18-11: Example SOEC Electrolyzer System from Bloom (Left) and an SOEC Cell from Topsoe (Right)

18.4.1.6 *Thermochemical Hydrogen Production (Sulfur-Iodine, Cerium Oxide, Copper Chloride)*

The final category of hydrogen production methods involves chemical reactions driven by high temperatures. In these cycles, utilized in intermediate stages are recycled. Thermochemical processes show promise due to the high efficiency observed during laboratory testing.[120] [121] [122] There are several variants of thermochemical cycles and efficiencies vary depending on the heat and electricity sources.

[120] Mehrpooya M, Habibi R, A review on hydrogen production thermochemical water-splitting cycles, Journal of Cleaner Production, Volume 275, 2020, 123836, ISSN 0959-6526, https://doi.org/10.1016/j.jclepro.2020.123836.

[121] Boretti A, Which thermochemical water-splitting cycle is more suitable for high-temperature concentrated solar energy? International Journal of Hydrogen Energy, Volume 47, Issue 47, 2022, Pages 20462-20474, ISSN 0360-3199, https://doi.org/10.1016/j.ijhydene.2022.04.159.

[122] Pinsky R, Sabharwall P, Hartvigsen J, O'Brien J, Comparative review of hydrogen production technologies for nuclear hybrid energy systems, Progress in Nuclear Energy, Volume 123, 2020, 103317, ISSN 0149-1970, https://doi.org/10.1016/j.pnucene.2020.103317.

The sulfur-iodine thermochemical process consists of three steps. Initially, water, iodine and sulfur dioxide are combined to generate hydrogen iodide and sulfuric acid in an exothermic reaction. These products are then separated and processed individually. The hydrogen iodide is decomposed with the addition of heat at 450°C to iodine and hydrogen gas. Similarly, the sulfuric acid is heated to 830°C to form sulfur dioxide, steam, and oxygen. Then the process is restarted, and more water is added. A significant challenge of this process is the isolation of hydrogen and oxygen through condensation. That is, the addition and removal of heat to acquire hydrogen and then purify it is a significant energy input into the process.

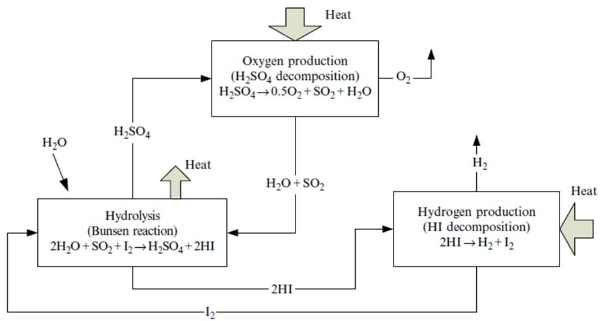


Figure 18-12: Schematic of the Sulfur-Iodine Thermochemical Process[123]

The cerium-oxide thermochemical process is a two-step process which requires temperatures up to 2000°C. In this twostep process, water is added in the hydrolysis step at 400°C. The immediate contact between the water and cerium(III) oxide is exothermic and produces hydrogen and cerium(IV) oxide. The hydrogen is collected and processed. The cerium(IV) oxide is then heated to 2000°C in the dissociation step and converted back to cerium(III) oxide with the release of oxygen. The convenience of this process resides in the fact that the only two steps are needed which effectively isolate the hydrogen and oxygen. The process does not require an electrical input to split the water. Unfortunately, the heat input required for the dissociation step is very high which limits the utility of the process.

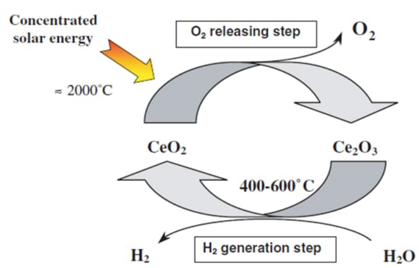


Figure 18-13: Schematic of the Cerium-Oxide Thermochemical Process[124]

[123] Ibrahim Dincer, Calin Zamfirescu, Chapter 4 - Hydrogen Production by Thermal Energy, Editor(s): Ibrahim Dincer, Calin Zamfirescu, Sustainable Hydrogen Production, Elsevier, 2016, Pages 163-308, ISBN 9780128015636, https://doi.org/10.1016/B978-0-12-801563-6.00004-2.

[124] Abanades, S., Flamant, G., Thermochemical hydrogen production from a two-step solar-driven water-splitting cycle based on cerium oxides, Solar Energy, Volume 80, Issue 12, 2006, Pages 1611-1623, ISSN 0038-092X, https://doi.org/10.1016/j.solener.2005.12.005.

Of all the technologies included in this work package, the thermochemical processes have the lowest TRL. These hydrogen production methods are observed in small prototype phases typically within research institutions. Nonetheless, they show promise for coupling with industrial process with high-grade temperature heat as waste or from heat generated by solar concentrators.

One other thermochemical process is the hybrid[125] Cu-Cl cycle The Cu-Cl cycle does have positive characteristics compared to the sulfur-iodine and cerium-oxide cycles. For example, the Cu-Cl cycle has the lowest temperature requirement of 530°C. However, the Cu-Cl cycle does require several stages and yields a more complex reactant handling process, which is shown in Figure 18-14. In addition, the hybrid nature of the cycle requires the addition of electricity.

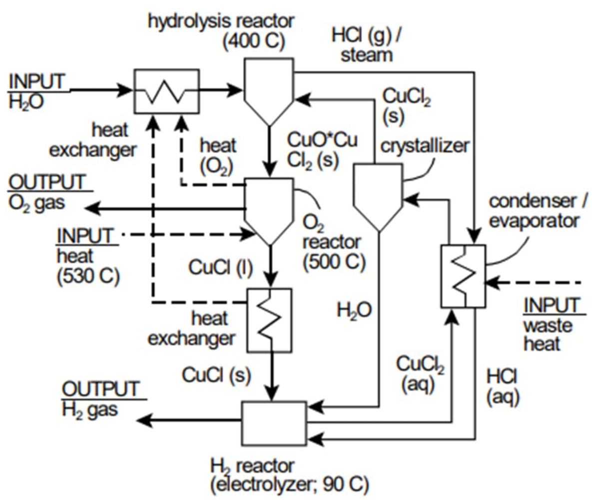


Figure 18-14: Schematic of the Cu-Cl hybrid Thermochemical Process[126]

Thermochemical processes create significant challenges for process engineers. A combination of reactive chemicals and high temperatures leads to unfavorable conditions for typical materials of construction, and limits material selection for tanks, pipes, valves, and other process components. Developments in materials compatibility and demonstrated performance is needed to advance the technology. Another challenge is the requirement for high grade heat, which is evident in the case of the cerium-oxide process where the necessary temperature is 2000°C. The temperature requirements also limit the compatibility with SMR technologies due to a gap between the reactor operating temperature and the thermochemical process maximum temperature.

[125] The Cu-Cl cycle requires temperatures up to 530°C to release oxygen and a low electric potential for electrolysis to generate hydrogen.
[126] Naterer, G. F., et al., “Progress in Thermochemical Hydrogen Production with the Copper-Chlorine Cycle”, International Journal of Hydrogen Energy, vol. 40, no. 19, pp. 6283 – 6295, May 2015.

18.4.2 Technology Analysis Criteria

18.4.2.1 Hydrogen Production Performance

The effect of increased input water temperature on electrolysis input energy requirements is shown in Figure 18-15 and a key observation is that hydrogen production processes utilizing steam have a lower total energy demand. Furthermore, an increase in water temperature reduces the electrical energy required for hydrogen production. The effect is observed in the liquid water region; however, the total energy demand is still higher when compared with steam. This is a key reason for improved efficiency among high temperature hydrogen production methods. In the analysis, the lowest stack and plant power consumption per normalized unit mass (kg) of hydrogen will receive a high ranking.

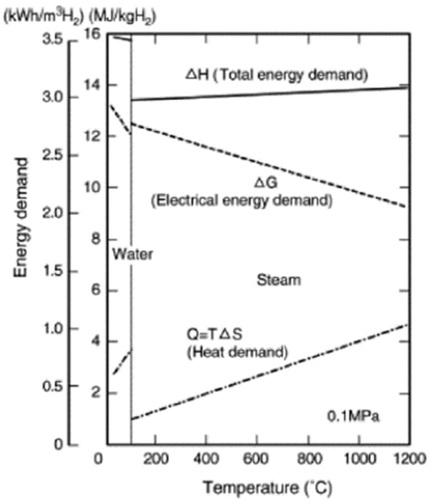


Figure 18-15: Electrolysis Energy Requirements for Water Liquid and Steam Phases [127]

For ease of integration to a nuclear energy plant, the minimum turndown ratio and ramp rates are also considered. A low turndown ratio allows the electrolyzer to operate with low available power for hydrogen production. Coupled with a fast ramp rate, the electrolyzer can accommodate a wide range of operating points with fast response to changing loads. Ultimately, these characteristics reflect on the load flexibility of the electrolyzer.

Another characteristic evaluated is the startup time of the system. A short start up time will receive high ranking. The startup time can vary greatly between low and high temperature processes. High temperature processes require thermal stability before they can be effectively operated.

Integration with an SMR was evaluated with two criteria: compatibility for integration and integration efficiency. Compatibility seeks to determine if prior projects have been completed where SMR was a critical stage. The integration efficiency quantifies the number of energy conversions or transfers from the nuclear heat source to the hydrogen production technology.

[127] Hino R., Haga K., Aita H., Sekita K., R&D on Hydrogen Production by High-Temperature Electrolysis of Steam, Nuc. Eng. Des. 233 (2004) 363-375.

As an example, the SOEC process requires electrical input and thermal input in the form of steam. The conversion to electricity takes two steps: heat is converted to electricity and then electricity is used to drive the electrolysis. In comparison a pure thermal process does not require electricity for the water splitting and, therefore, only has one step. Electricity for the BOS was excluded from this criterion and only the hydrogen producing mechanism was evaluated.

Other technical assessment factors are as follows:

- The highest hydrogen purity from the hydrogen production plant will receive the highest ranking.
- Availability and lifetime of the hydrogen production process is needed for evaluation of technology longevity. Maximum availability and lifetime hours receive the highest ranking.

Finally, the technology readiness level (TRL) is included in the technical evaluation to compare the commercial readiness. A high TRL is preferred, but technologies that are expected to mature during the development of the SMR facility are also under consideration. Therefore, the threshold is TRL ≥ 8 for high ranking.

18.4.2.2 Site Compatibility

Site compatibility is meant to focus on the electrolyzer plant's footprint and modularity. Minimal footprints will receive high ranking. Modularity is concerned with dense packaging and the ability to quickly scale the electrolyzer.

18.4.2.3 Schedule

The purpose of the schedule category is to evaluate the vendor's lead time and to compare the vendor's overall production capacity. The lowest lead time will receive a high ranking and the highest production capacity will receive a high ranking.

18.4.2.4 Operation

The operation category indicates the number of employees necessary to operate the system, and the availability of spare parts. The minimum number of employees will receive a high ranking. The availability of spare parts will also receive a high ranking.

18.4.2.5 Financials

The financial category includes CAPEX and OPEX values to establish a cost per kW installed. The CAPEX and OPEX is expected to have higher confidence for high TRL technologies which is reflected in the confidence values included in this assessment. An AACE Class 5 estimate uncertainty range has been adopted as the threshold in this assessment.

In this category the minimum CAPEX and OPEX values will receive a high ranking, and low estimated variance relative to an AACE Class 5 estimate uncertainty value will receive high ranking.

18.4.3 Evaluation Methodology

The hydrogen technologies were evaluated according to five categories described in the preceding section:

- Hydrogen production performance.
- Site compatibility.
- Schedule.
- Operation, and
- Financial.

Each category had an integer value assigned in the range [0, 3]. The values represented the significance of the category, where 0 represents that the category is assigned no significance in this assessment while 3 represents a critical success factor. Each category value was divided by the sum of all category values to produce the relative category weighting. The sum of the relative category weighting was 1.0.

Next, each category was further divided into evaluation criteria. Again, an integer value was assigned to each criterion in the range [0, 3], and the value was divided by the sum of criteria values for that category to produce the criterion weighting. This value represented the significance of the criterion within the evaluation category.

Finally, the product of the category weighting and the criterion weighting was used as the scaling factor. Utilizing this method allows a maximum score of 1.0 for any technology evaluation. The assignment of values for categories and criteria was based on expert judgement.

For each of the criteria, when the baseline threshold is met or exceeded, full scores are awarded to the technologies evaluated. If the baseline is not met, then a ratio between the evaluated value and the baseline is multiplied by the scaling factor.

A final evaluation is completed by calculating the sum of all evaluated categories pertaining to each hydrogen production process. The highest value for low and high temperature processes will be reported.

18.4.4 Technology Evaluation Weighting

The evaluation weightings were assigned based on a workshop and SME review. The highest rated categories were performance and finance, followed by schedule, and then finally the lowest rated were site compatibility and operation.

At this phase of the project, the technical performance establishes a case for integration with an SMR. The financial ranking also supports a path by emphasizing the most economical path forward. Scheduling, namely lead time and vendor capacity, were the next rated category due to the need for alignment with the SMR construction schedule. That is, when the equipment cannot be commercialized within the SMR construction timeline, it is rated lower relative to the other processes. The lowest rated categories, site compatibility and operation, were of reduced interest due to the early stages of this project.

18.4.5 Hydrogen Production Evaluation Results

The highest-ranked low temperature electrolysis process was AWE. The rating was very close with PEM, and both would operate adequately when integrated to an SMR. Given the assumption that the SMR would be dedicated to hydrogen production, it can be expected for the power to be constant which aligns with the AWE operations requirements. Furthermore, the AWE process has accrued longer operating time and has the highest TRL of all the hydrogen production processes. The efficiency – both electrical efficiency and yield efficiency – was highest for AWE. The CAPEX and OPEX variance were the lowest for PEM and AWE which is expected from commercialized technologies. AWE does have a longer start up time and cannot be easily throttled compared to PEM. Furthermore, the AWE process requires the processing and storage of KOH which requires specialized handling.

The highest-ranking high temperature process was the SOEC. The SOEC would utilize the steam and some electrical energy to generate hydrogen at an efficiency much better than low-temperature electrolysis. The technology has also been tested with a nuclear reactor.[128] In reviewing other high temperature processes, there was a significant gap in available information between SOEC and thermochemical processes. This is because all three thermochemical processes possess low TRL values and most information is provided from research articles. One of the key pieces of missing information was the estimated CAPEX and OPEX values. As mentioned previously in the report, the performance characteristics and financial data were the highest rated categories, therefore, without this data the thermochemical processes lose significant points in the ranking. The thermochemical processes should be re-evaluated in later phases of this project to obtain more data.

18.5 Hydrogen Cost Options and LCOH

The LCOH calculation was prepared to generate a baseline for the technology evaluation. All values are presented in USD [CAD]. The LCOH was calculated using the equation below:

$$LCOH = \frac{\sum_{t=0}^{P+C-1} \frac{CAPEX_t + OPEX_t}{(1+i)^t}}{\sum_{t=0}^{P+C-1} \frac{Production}{(1+i)^t}}$$

The values presented in Table 18-1 were utilized in the financial model. The main differences between the two processes included efficiency, CAPEX and refurbishment intervals. It is important to note that the LCOH is provided independent of the SMR levelized cost.

[128] Bloom Energy Press Release: Bloom Energy and Idaho National Laboratory to Generate Hydrogen Powered by Nuclear Energy - Bloom Energy.

Table 18-1: LCOH Inputs and Results

Parameter	Alkaline Water Electrolyzer Plant	SOEC Electrolyzer Plant
Electrical Power, MWe	82.5	
Process Efficiency (Stack), kWh/kg	56	42
BOP Power Consumption, %	10	
Degradation Rate, %/year	1	
Plant Availability, %	95	
Plant Life, years	30	
Discount Rate, %	8	
Electricity Cost, $/MWh	46 USD [61 CAD]	
CAPEX, $/kW	2000 USD [2660 CAD]	4000 USD [5320 CAD]
Sustaining CAPEX, $/kW	500 USD [665 CAD]	
Refurbishment Interval, years	10	15
Maintenance, %/year	3	
Production Capacity, Mtpd	35.36	47.14
LCOH, $/kg	4.67 USD [6.21 CAD]	4.61 USD [6.13 CAD]
LCOH Breakdown, $USD/kg CAPEX OPEX Sustaining CAPEX	 1.19 3.18 0.29	 1.79 2.61 0.20

Based on the above data, the LCOH is calculated to be $4.67/kg [$6.21/kg CAD] for AWE and $4.61/kg [$6.13/kg CAD] for the SOEC process. The LCOH values represent a difference of approximately $0.06/kg USD, but it should be noted that the LCOH may vary once detailed engineering is initiated. It should also be noted that the CAPEX and OPEX variance levels are higher for the SOEC option, which means the actual LCOH for a fully designed plant may be higher. This is because the largest SOEC installation now is only 2.6 MW[129], whereas for AWE is 150 MW as mentioned earlier. As a result, for near term installations AWE systems are suggested.

129 IEA (2022), Electrolyzers, IEA, Paris https://www.iea.org/reports/electrolyzers.

Looking at the LCOH breakdown, the difference in CAPEX is overshadowed by difference in OPEX. That is, the high CAPEX for the SOEC is offset by the low combined OPEX and sustaining CAPEX, and the higher hydrogen production capacity due to the higher efficiency.

Sensitivity studies were also performed for plant utilization, electricity cost and discount rate for the selected processes. The data in Figure 18-16 and Figure 18-17 present similar variations when the noted variables are changed. That is, utilization must stay high to maintain a low LCOH, and lower electricity costs reduce LCOH as expected. The discount rate aides in showing the possible LCOH with varying financial model inputs. The impact of varying the discount rate for both scenarios is shown in Table 18-2, and the values are relative to the base case presented in Table 18-1. In both scenarios, the highest variation is observed through plant utilization.

Table 18-2: LCOH Variation Due to Discount Rate, Relative to 8% (Base Case), $/kg H2

Discount Rate	6%	8% (Baseline Case)	10%	14%
AWE Scenario ($)	- 0.20	0.00	+ 0.22	+ 0.68
SOEC Scenario ($)	- 0.31	0.00	+ 0.33	+ 1.05

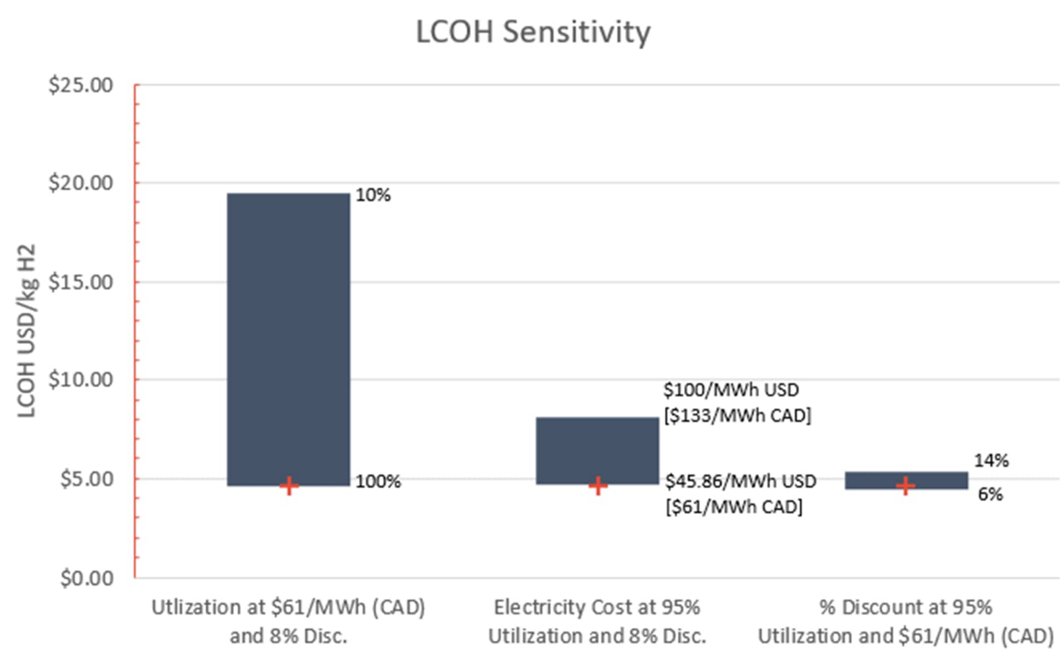


Figure 18-16: AWE LCOH Sensitivity Plot. Red Cross Indicates Calculated Scenario

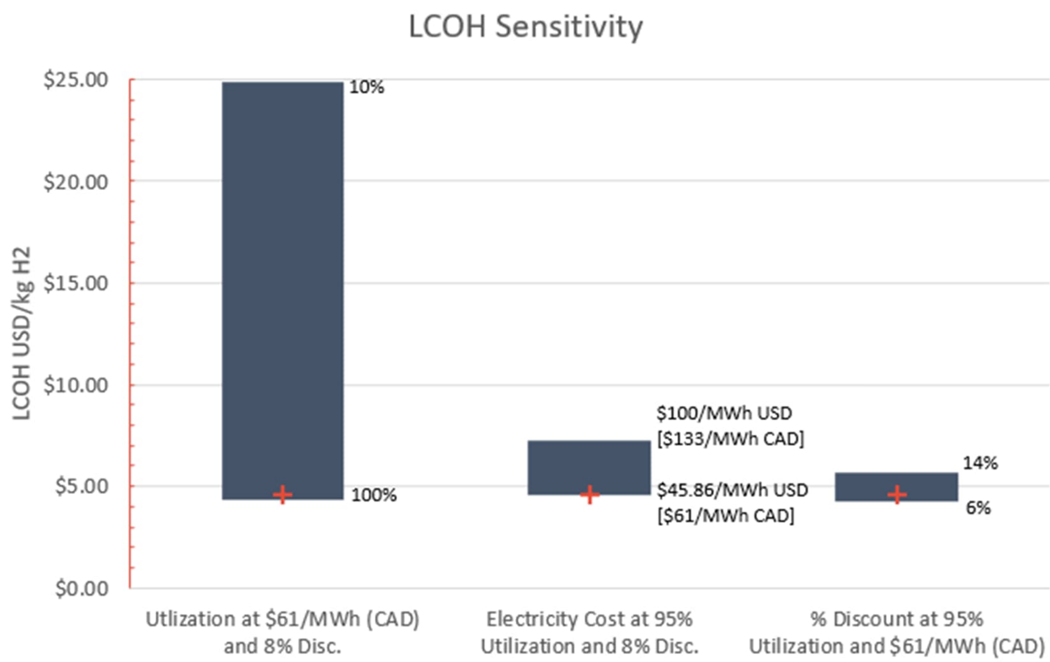


Figure 18-17: SOEC LCOH Sensitivity Plot. Red Cross Indicates Calculated Scenario

18.6 Conceptual Plant Block Diagrams

The AWE process conceptual block diagram is shown in Figure 18-18. Input water must be filtered prior to use with AWE. An alkaline mixture is then formed when combined with the hydroxide solution. The AWE process requires cooling water to keep the equipment at operation temperatures. Hydrogen product must flow through a purifier (oxygen removal, if required), dryer and compression stage before use. The input power to the electrolyzer is DC which requires a transformer and rectifier. Additional AC power is used for controls and other BOS components.

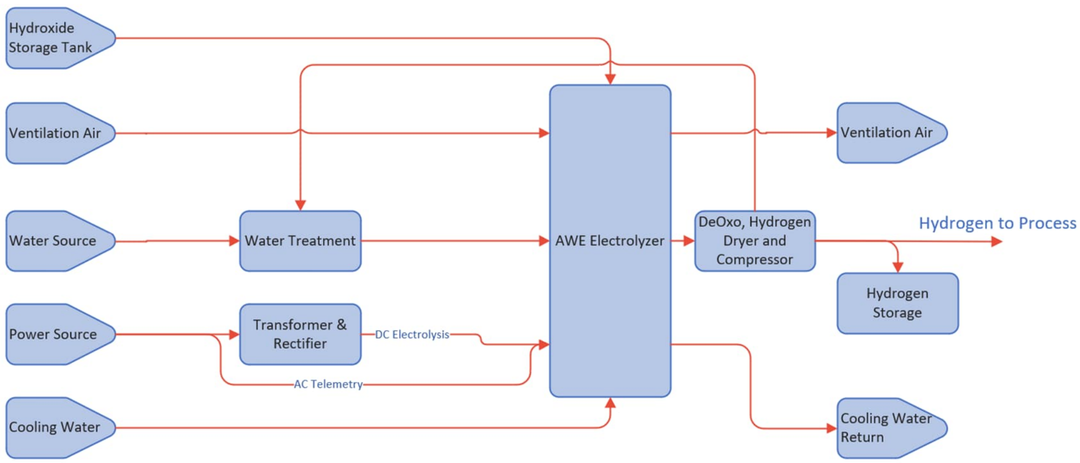


Figure 18-18: AWE Conceptual Plant Block Diagram

A conceptual hydrogen production plant layout for the SOEC process is shown in Figure 18-19. The SOEC process has steam as input and an optional steam generator is shown. It should be noted that for startup, pure hydrogen is required. On the product side, the hydrogen must flow through a drying and compression stage before use or storage. The input power to the electrolyzer is DC which requires a transformer and rectifier. Additional AC power is used for controls and other BOS components.

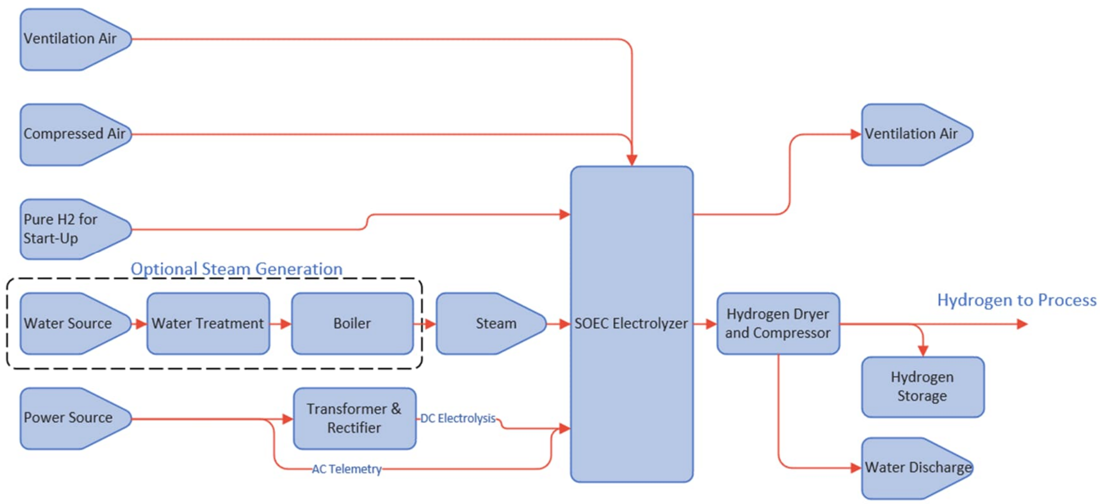


Figure 18-19: SOEC Conceptual Plant Block Diagram

18.7 Conclusion

The study completed an evaluation of low temperature and high temperature hydrogen production processes. Using a Pugh Matrix, the AWE and SOEC processes were selected as feasibly low and high temperature candidates, respectively, for integration with an SMR. The LCOH was calculated for AWE and SOEC processes and the results showed better value with SOEC due to the higher CAPEX of the SOEC being counteracted by the higher production and efficiency of SOEC. The current suggestion is to utilize the AWE process because it has more use time and larger commercial scale relative to SOEC. Furthermore, between the two processes the AWE scored higher in the evaluation matrix.

The efficiency from source to sink provides a meaningful comparison between competing technologies by identifying an optimized energy transfer. In the scenario to provide SAGD steam heating Table 18-3 shows the energy path for two configurations: SMR heat to steam, and SMR heat to hydrogen to steam.

Table 18-3: Energy Path from Source (SMR) to Sink (Steam Generation)

Configuration	Steam Generation Efficiency	Electricity Generation Efficiency (2 Steps[130])	Hydrogen Generation Efficiency	Hydrogen Combustion to Heat Generation Efficiency	Total Efficiency
SMR Heat to Steam	>95%	-	-	-	>95%
SMR Heat to Hydrogen to Steam	-	33%[131]	88%[132]	70%[133]	20%

The table shows the number of steps between the source and sink. By inspection, generating steam directly from the SMR heat only has a single step, whereas the alternative path which includes hydrogen has four (2 steps: SMR heat to steam to electricity). The resulting efficiencies are 95% for direct steam generation and 20% for steam generation with hydrogen.

In these scenarios, the direct heat transfer from the SMR is more efficient to produce steam instead of producing hydrogen and then subsequently burning it to generate heat for steam production. Furthermore, the addition of steps increases the levelized cost of the final steam product due to additional equipment.

In future phases of the project an update to the evaluated technologies should be completed. The coupling of AWE to an SMR is feasible. Additional design development is needed as a conceptual or feasibility study. The design work would provide a more detailed view of the reactor integration.

19. Summary and Key Takeaways

SMRs are a feasible option for the provision of electricity and steam in the oil sands to support net-zero energy production at in-situ recovery facilities. While no specific recommendations are made in this report, major considerations associated with SMR deployment planning are presented along with commentary to assess the potential impacts of decisions and their influence on other decisions.

Given the need for both process steam and electricity in the reference SAGD facility, it is suggested that all generated nuclear energy should supply heat to a common header/storage loop. By passing the heat through a common loop, the reliability of SAGD steam production

[130] Combined efficiency of initial steam generation and electricity generation via steam turbine.
[131] As per assumptions in hydrogen section. Efficiency may vary 31% to 44% depending on reactor type.
[132] Assuming SOEC efficiency, HHV.
[133] Assuming 100% hydrogen.

can be improved through SMR outages based on the ability to preferentially generate steam instead of providing power to the grid.

In Canada, sites for hosting SMRs are expected to be evaluated using a graded approach, commensurate with risks posed by the facility's operating parameters. Potential licensees are expected to have flexibility in identifying specific locations for SMRs at existing SADG operations and are expected to demonstrate this through the site licensing process and impact assessment review. Flexibility in site identification can support the deployment of SMRs at industrial sites by allowing licensees to best utilize site areas and to ensure that no undue risk is posed by existing features of the site (i.e., industrial processes).

Complex, inter-governmental regulatory context is important to understand, notably due to the novel and untested regulatory environment posed by the deployment of a First-of-a-Kind (FOAK) SMR in Alberta. This context provides an understanding of how regulatory factors might influence the feasibility for nuclear- powered generation within Alberta's oil and gas sector. The FOAK considerations that present uncertainty in the overall regulatory process, will most likely result in increased timelines for approvals needed for navigating the regulatory landscape. Nonetheless, the Government of Canada has repeatedly signalled its readiness for the emerging use of SMRs across the country and is committed to ensuring the safe use of nuclear energy for the next generation of reactors. Engaging with Indigenous and non-Indigenous community members is an essential part of any project's master planning process – particularly when discussing new technology associated with nuclear energy, which is tantamount to introducing a new industry.

In the planning of any nuclear power project at a SAGD facility, the following critical items should be considered.

- The integration of an SMR with a SAGD operation represents a novel application of nuclear technology. Ensuring nuclear and industrial safety is paramount.
- As with any major project, early engagement with the CNSC, IAA, and other regulators and stakeholders is needed. Given the introduction of a new technology (nuclear) into a new jurisdiction, building relationships with Indigenous and local communities will be required to ensure an informed, receptive community supportive of the deployment of this new technology as a part of overall decarbonization plans.
- Due to the regulations around the management of nuclear power plants, existing nuclear power plant operators should be leveraged to operate the first SMRs for supporting SAGD facilities. Over time, additional operations models may be investigated; however, partnering with existing nuclear operations organizations provide a significant benefit to project viability in the near term.
- For any potential SMR deployment, a detailed site assessment following the principles and guidance provided by both the CNSC and the IAEA should be completed to ensure that the sites do not possess any fatal flaws, significant issues impacting overall cost or schedule, or external hazards introduced due to the co-location next to an active

industrial facility. As SAGD operations represent a novel application of nuclear technology, ensuring a robust assessment of both site and integration conditions will be important for licensing and technical development.

- Different SMR technologies exist to address the steam and power demands of SAGD facilities. To ensure that an optimal technology partner has been selected, a robust down selection of SMR technologies should be conducted reflective of the SAGD sites operational and business needs.

Appendix A: Generic SAGD Operational Scheme BFD

DRAWING No.	DRAWING TITLE

REFERENCE DRAWINGS

NAME

SIGNATURE

ENG REG NUMBER

REVISION DATE

ORIGINAL DATE

REG. PROFESSIONAL

Reserved space for Issue Reason stamp applied by Document Control

No.	DESCRIPTION	BY	CHK'D	DATE
1	ISSUED FOR INFORMATION (H370496)	-	-	-

REVISIONS

HATCH

ROLE	NAME	SIGNATURE	DATE
DRAFTSPERSON			
DESIGNER	-		
CHECKER			
DESIGN COORD.			
RESP. ENG.	-		
LEAD DISC. ENG.			
ENG. MANAGER			
PROJ. MANAGER			

DRAWING APPROVAL STATUS:

ALBERTA INNOVATES

GENERIC STEAM ASSISTED GRAVITY DRAINAGE
OPERATIONAL SCHEME BLOCK FLOW DIAGRAM

SMALL MODULAR REACTOR (SMR)
FEASIBILITY STUDY

SCALE	DWG. No.	REV
OR AS NOTED		1

SHEET SIZE: D

Appendix B:
SMR SAGD Integration BFD

DRAWING No.	DRAWING TITLE
REFERENCE DRAWINGS	

NAME
SIGNATURE
ENG REG NUMBER
REVISION DATE
ORIGINAL DATE
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DESIGN COORD.			
RESP. ENG.	-		
LEAD DISC. ENG.			
ENG. MANAGER			
PROJ. MANAGER			

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ALBERTA INNOVATES

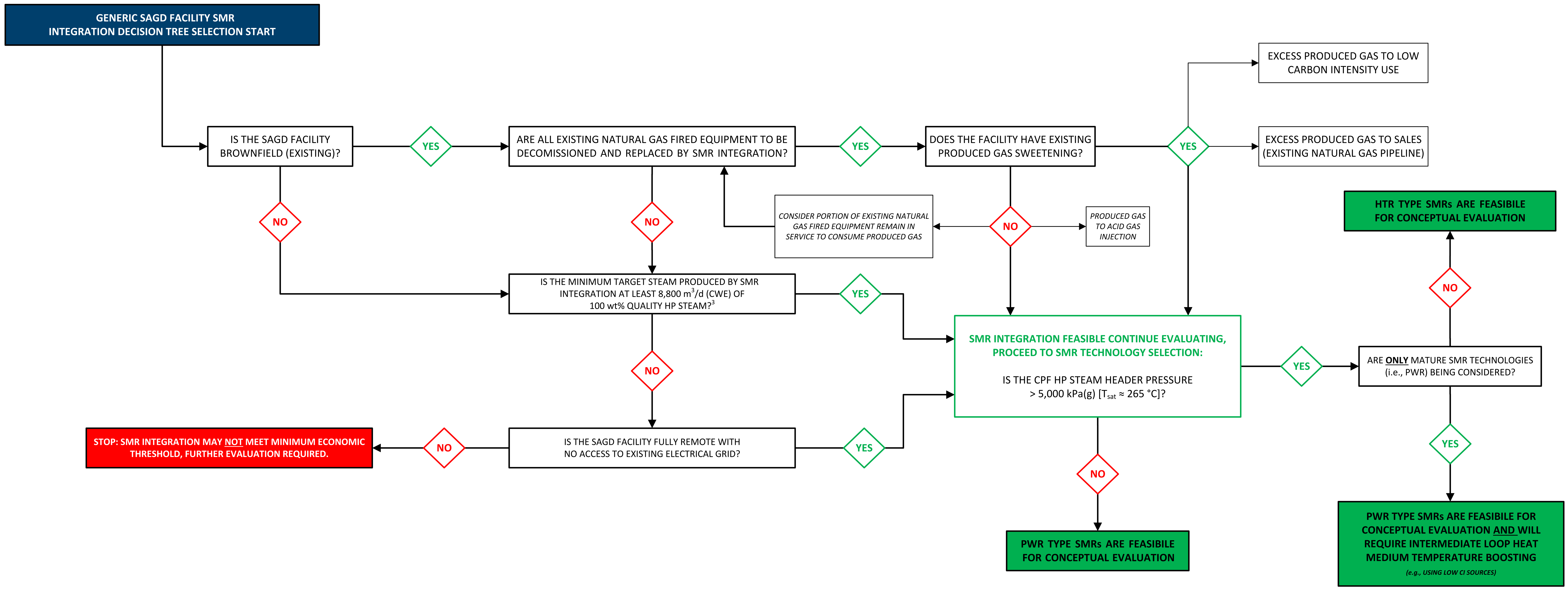
SAGD SMR INTEGRATION BLOCK FLOW DIAGRAM

SMALL MODULAR NUCLEAR REACTOR (SMR) FEASIBILITY STUDY

SCALE	DWG. No.	REV
OR AS NOTED		1

SHEET SIZE: D

Appendix C: Generic SAGD Facility SMR Integration Decision Tree Selection Tool



NOTES:

1. *ABBREVIATIONS:* **CI** – CARBON INTENSITY; **CWE** – COLD WATER EQUIVALENT [STEAM VOLUMETRIC FLOW]; **CPF** – CENTRAL PROCESSING FACILITY (SAGD); **HTR** – HIGH-TEMPERATURE REACTOR [SMR TYPE]; **HP** – HIGH PRESSURE; **PWR** – PRESSURIZED WATER REACTOR [SMR TYPE]; **SAGD** – STEAM ASSISTED GRAVITY DRAINAGE; **SAT** – SATURATED [STEAM CONDITIONS]; **SMR** – SMALL MODULAR REACTOR; **wt%** - MASS PERCENT

2. THIS DECISION TREE IS TO PROVIDE CONTEXT FOR SELECTION OF SMR INTEGRATION WITH THERMAL IN SITU OIL SANDS SAGD OPERATIONS AND IS INTENDED FOR ILLUSTRATION/INFORMATION ONLY.

3. 8,800 m^3/d CWE IS EQUIVALENT TO 8,800 t/d STEAM FLOW RATE, WHICH IS ASSOCAITED TO THE USE OF APPROX. ONE (1) 200 MW_{th} SMR.

DRAWING No.	DRAWING TITLE
REFERENCE DRAWINGS	

NAME
SIGNATURE
ENG REG NUMBER
REVISION DATE
ORIGINAL DATE
REG. PROFESSIONAL

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REVISIONS

HATCH

ROLE	NAME	SIGNATURE	DATE
DRAFTSPERSON			
DESIGNER	-		
CHECKER			
DESIGN COORD.			
RESP. ENG.	-		
LEAD DISC. ENG.			
ENG. MANAGER			
PROJ. MANAGER			

DRAWING APPROVAL STATUS:

ALBERTA INNOVATES

GENERIC SAGD FACILITY SMR INTEGRATION
DECISION TREE SELECTION TOOL

ALBERTA INNOVATES
SMALL MODULAR REACTOR
FEASIBILITY STUDY

SCALE	DWG. No.	REV
OR AS NOTED		1

SHEET SIZE: D

Appendix D:
High Temperature (HT) SMR SAGD Interface PFDs

DRAWING NUMBER	REFERENCE DRAWING

REV	DATE (YYYY-MMM-DD)	DESCRIPTION	BY	CHECK	ENG	APP	PM
–	2023–JUN–09	ISSUED FOR INFORMATION	VC	–	–	–	–

–

PROCESS FLOW DIAGRAM
SMR INTEGRATION ISLAND

SCALE	DRAWING NUMBER	REV.
NTS	–	A

Size = 863x559

Appendix E:
HT SMR Integration Heat and Material Balance Table

Material Streams

Fluid Pkg: All

Name		HTR-S1	HTR-S2	HTR-S3	HTR-S4	HTR-S5	HTR-S6	HTR-S7	HTR-S8	HTR-S9	HTR-S10
Vapour Fraction		0.0000	0.0000	0.0000	0.8519	0.9973	0.0000	0.0000	1.0000	0.0000	0.0000
Temperature	(C)	175.0	195.0	215.0	313.1	311.6	313.1	193.8	550.1	275.5	250.0
Pressure	(kPag**)	1.050e+004	1.040e+004	1.030e+004	1.020e+004	1.000e+004	1.020e+004	1.000e+004	1.690e+004	1.670e+004	1.650e+004
Molar Flow	(kgmole/h)	4.266e+004	4.266e+004	4.266e+004	4.266e+004	3.634e+004	6317	6317	3.090e+004	3.090e+004	3.090e+004
Mass Flow	(kg/h)	7.685e+005	7.685e+005	7.685e+005	7.685e+005	6.547e+005	1.138e+005	1.138e+005	5.567e+005	5.567e+005	5.567e+005
Liquid Volume Flow	(m3/h)	770.0	770.0	770.0	770.0	656.0	114.0	114.0	557.8	557.8	557.8
Heat Flow	(MW)	-3240	-3221	-3202	-2859	-2401	-458.5	-477.2	-1932	-2275	-2295

Compositions

Fluid Pkg: All

Name	HTR-S1	HTR-S2	HTR-S3	HTR-S4	HTR-S5	HTR-S6	HTR-S7	HTR-S8	HTR-S9	HTR-S10
Master Comp Mass Frac (H2O)	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

Energy Streams

Fluid Pkg: All

Name		QSMR									
Heat Flow	(MW)	362.0									

Appendix F:
Initial Reactor List

Green:	This reactor design has passed the initial screening and is recommended for further evaluation

SMR Technology Long List

Reactor Name	Developer	Country of origin	Capacity, MWe	Capacity, MWth	Type
4S	Toshiba	Japan	10	30	LMFR
ABV-6M	OKBM Afrikantov	Russia	6 to 9	38	IPWR
ACP100	NPIC/CNNC	China	125	385	IPWR
ACPR50S	CGN	China	60	200	PWR
ACPR100S	CGN	China	140	450	IPWR
Adams Engine	Adams Atomic Engines	USA			HTR
AHTR	Eskom Holdings SOC Ltd.	South Africa	50	100	HTGR
AHWR	Babha Atomic Research Center (BAR	India	304	920	BHWR
ALLEGRO	European Partners	Various, European	xx	75	HTR
ANGSTREM	OKB Gidropress	Russia			lead
ANTARES	AREVA --> framatome	France	325	750	HTR
AP-300	Westinghouse	USA	300	900	PWR
ARC-100	Advanced Reactor Concepts	Canada, USA	100	286	LMFR
AURORA	Oklo, MIT	USA	1.5	4	lead
BANDI-60S	Kepco	South Korea	60	200	PWR
BANR	BWXT Technologies	USA	xx	50	HTGR
BMN-170	OKBM, IPPE	Russia	170		LMFR
BN GT-300	RDIPE	Russia	300		LMFR
BREST	RDIPE	Russia	300	700	lead
BWRX-300	GE-Hitachi	USA	300	870	BWR
CANDU-6	SNC-Lavalin	Canada	680	2061	PHWR
CANDU-300	SNC-Lavalin	Canada	300	960	PHWR
CAREM	CNEA & INVAP	Argentina	25	100	IPWR
CAP150	SNERDI	China	150	450	PWR
CAP200	SNERDI	China	200	660	PWR
CAWB	UK Atomics (parent Copenhagen At	UK/Denmark	xx	100	MSR
CEFR	CNEIC	China	20	65	LMFR
CMSR	Seaborg Technologies	Denmark	100	250	MSR
CNP-300	CNNC, SNERDI	Pakistan & China	310	966	PWR
DHR400	SPIC/SNERDI	China		400	PWR
EGP-6	Unknown	Russia	11	62	LWGR
EM2	General Atomics	USA	265	500	HTGR
ENHS	University of California (Berkeley)	USA	50		LMFR
eVinci	Westinghouse	USA	3.5	12	
FBNR	Federal University of Rio Grande do	Brazil	70	218	Fixed Bed
Flexblue	DCNS	France			PWR
FMR	General Atomics	USA	50	100	GCFR
Fuji MSR	International Thorium Energy & Mo	Japan	200	450	MSR
GEM*STAR	Virginia Tech and ADNA Corp.	USA			MSR
Gen4 module	Gen4 (Hyperion)	USA	25	70	
GFP HTGR	GFP, USNC, Hyundai(?)	Canada, USA			HTGR
GT-MHR	OKBM Afrikantov	Russia	288	600	HTGR
GTHTR	Japan Atomic Energy Agency (JAEA)	Japan	xxx	600	HTR
HAPPY200	SPIC	China	0	200	PWR
HTR-PM	Institute of Nuclear Energy and New	China	105	250	HTR
HTTR-30	Japan Atomic Energy Agency (JAEA)	Japan	0	30	HTGR
Hybrid	Hybrid Power Technologies	USA	xxx	600	HTGR

IMR	Mitsubishi heavy Ind, Japan	Japan	350	1000	IPWR
i-SMR	KHNP & KAERI	South Korea	170	540	
Integral MSR	Terrestrial Energy	Canada	195	400	MSR
IRIS	International Consortium		335	1000	IPWR
KLT-20	OKBM Afrikantov	Russia	20	85	PWR
KLT-40S	OKBM Afrikantov	Russia	35	150	PWR
KP-FHR	Kairos Power	USA	140		salt-cooled
KP-Hermes	Kairos Power	USA	0	35	salt-cooled
Leadir-PS100	Northern Nuclear	Canada			lead
L-ESSTAR	LakeChime				LMFR
LFR-AS-200	Hydromine Nuclear Energy		200		LMFR
LFR-TL-X	Hydromine Nuclear Energy		20		LMFR
LFR-mini	Newcleo	UK-headquarter	30	90	lead
LFR-small	Newcleo	UK-headquarter	200	480	lead
LFTR	Flibe Energy	USA	250	600	MSR
LSPR	Tokyo Institute of Technology	Japan	53	150	LMR
MARS	Kurchatov Institute	Russia	6		MSR
MHR-T	OKBM Afrikantov	Russia	51	150	HTGR
microURANUS	UNIST (a university)	South Korea	20	60	lead
MMR	USNC	USA, some Can	10	30	HTGR
moltexFlex	Moltex Energy	Canada, UK	16	40	MSR
mPower	Babcock & Wilcox + Bechtel	USA	195	575	IPWR
MRX	Japan Atomic Energy Research Instit	Japan			IPWR
MTSPNR (GREM)	N.A. Dollezhal Research and Develo	Russia	2		HTR
NHR-200	NHR-200, Chinese Tsingua Universit	China		200	IPWR (heat)
NIKA-70	N.A. Dollezhal Research and Develo	Russia	15		PWR
NP-300	Technicatome (AREVA)				IPWR
Nucell	GMET	UK			
Nuward	EDF, CEA, TA, Naval Group	France	170	540	IPWR
Open-20	Last Energy	USA	20	60	PWR
PBMR	South Africa; NPMC, USA*				HTR
PEACER	Nuclear Transmutation Energy Rese	South Korea	300	850	LMR
PHWR-220	NPCIL	India	235	754	PHWR
Prism	GE-Hitachi	USA	311	840	LMFR
DEER	Radix Power and Energy Corporatio	USA			PWR
RADIX Power	Radix Power and Energy Corporatio	USA			PWR
RAPID	Central Research Institute of Electri	Japan			LMR
RDE	BATAN	Indonesia	xx	40	HTGR
RITM-200N	OKBM Afrikantov	Russia	55	175	IPWR
RITM-200	OKBM Afrikantov	Russia	55	175	IPWR
RUTA-70	RDIPE	Russia	70		PWR
SAKHA-92	OKBM Afrikantov	Russia	1		PWR
SC-HTGR (Antares)	AREVA --> framatome	USA	285	625	HTR
Sealer	LeadCold	Sweden/Canada	10	25	lead
Sealer-55	LeadCold	Sweden/Canada	55	140	lead
SHELF	RDIPE	Russia	6		PWR
SMART	KAERI	South Korea	107	365	PWR
SMART (UNITHERM)	Dunedin		6	30	
SMR-160	Holtec	USA	160	525	PWR
SSR-W	Moltex Energy	Canada, UK	xxx or 300	750 or 1250	MSR
SUPERSTAR	Argonne National Laboratories		120	300	LMFR
STAR (STAR-LM, STAR	Argonne National Laboratories		20	45	LMFR
STAR	Star Energy	Switzerland	10	30	IPWR
Starcore HTGR	StarCore	Canada	20 or 60	50 or 150	HTGR
STL	Steenkampskraal Thorium Limited	South Africa	35	100	HTR

SVBR-100	AKME-engineering	Russia	100	280	lead
TAP	Transatomic	USA			MSR
Teplator	UWB Bilsen & CIIRC UTC	Czech Republic	0	150	PHWR
Thorcon MSR	Martingale	USA	250	557	MSR
Thorenco	Thorenco				LMFR
TMSR-LF	SINAP	China	168	373	MSR
TMSR-SF	SINAP	China	168	384	MSR
TRIGA power system	General Atomics	USA	16.4	64	PWR
U-Battery	Urenco	UK and Canada	4	10	HTGR
UNITHERM	NIKIET, RDIPE	Russia	6.6		PWR
VBER-150	OKBM Afrikantov	Russia	110		PWR
VBER-300	OKBM Afrikantov	Russia	325	917	IPWR
VK-300	RDIPE, IPPE	Russia	250	750	BWR
VKT-12	OKB Gidropress	Russia	12		BWR
VOYGR	NuScale Power + Fluor	USA	77	250	PWR
VVER-300	OKB Gidropress	Russia	300		PWR
Westinghouse SMR	Westinghouse	USA	>225	800	IPWR
Xe-100	X-energy	USA	82.5	200	HTR

Medium and Large Reactors					
Reactor Name	**Developer**	**Country of origin**	**Capacity, MWe**	**Capacity, MWth**	**Type**
APR1400	KEPCO	South Korea	1400	3983	PWR
AP1000	Westinghouse	USA	1100	3415	PWR
APWR	Mitsubishi + others	Japan	~1600	~4000	PWR
EPR	EDF, Framatome, Siemens	mostly France	1650	4590	PWR
Hualong One	CNNC and CGNPC	China	1090		PWR
VVER-600	OKBM, Gidropress	Russia	600	1724	PWR
VVER-1500	Moscow Atomenergoproekt and Sai	Russia	1560		PWR
MSFR	CNRS	France	~1500	~3000	MSR
Molten Chloride Fast	Southern Company Services, Terrap	USA	~1000 MW	~2000 MW	MSR
Natrium	Terrapower	USA	345	840	LMFR
Travelling wave	Terrapower	USA	~1000		LMFR
UK SMR	Rolls-Royce	UK	470		PWR
BN-800	OKBM	Russia	800	2100	LMFR
BN-1200	OKBM	Russia	1200		LMFR
Westinghouse LFR	Westinghouse	USA	450	950	LMFR
CAP1400	SNPTC	China	1400		PWR

Appendix G: Technology Readiness Table Adapted from the Government of Canada

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
Fundamental Research	TRL 1	Basic principles observed and reported	Scientific research begins with properties of a potential technology observed in the physical world. These basic properties are being reported in the literature.
	TRL 2	Technology and/or application concept formulated	Applied research begins with identification of practical applications of basic scientific principles. There is an emphasis on understanding the science better and corroborating the basic scientific observations made during TRL 1 work. Analysis of the feasibility of speculative applications is being conducted and reported in scientific studies.
Research and Development	TRL 3	Experimental proof of concept	Active research and development begin. The applications are being moved beyond the paper stage to experimental work. Feasibility of separate technology components are being validated through analytical and laboratory studies. There is not yet an attempt to integrate components into a complete system.
	TRL 4	Validation of component(s) in a laboratory environment	Basic technological components are integrated "ad-hoc" to establish that they will work together in a laboratory environment. The "ad-hoc" system would likely be a mix of on hand equipment and a few special purpose components that may require special handling, calibration, or alignment in order to function.
	TRL 5	Validation of semi-integrated component(s) in a simulated environment	The integrated basic technological components are performing for the intended applications in a simulated environment. Configurations are being developed but can undergo fundamental changes. The technology and environment at TRL 5 are more similar to the final application than TRL 4.
Pilot and Demonstration	TRL 6	System and/or process prototype demonstrated in a simulated environment	A model or prototype, that represents a near desired configuration, is being developed at a pilot scale, generally smaller than full scale. Testing of the model or prototype is being conducted in a simulated environment.
	TRL 7	Prototype system ready (form, fit, and function) demonstrated in an appropriate operational environment	A full-scale prototype is being demonstrated in an operational environment but under limited conditions (i.e., field tests). At this stage, the final design is very close to completion.
	TRL 8	Actual technology completed and qualified through tests and demonstrations	Technology is being proven to work in its final form and under expected conditions. This stage commonly represents the end of technology development. At this stage, operations are well understood, operational procedures are being developed, and final adjustments are being made.
Early Adoption	TRL 9	Actual technology proven through successful	Actual application of the technology in its final form is being conducted under a full range of operational conditions. Sometimes referred to as "system

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
		deployment in an operational environment	operations", this stage is where technology is further refined and adopted.

Appendix H:
Proponent Strength and Readiness Level

Licence Applicant					
Readiness Level	Operating Experience	Reputation	Financial Strength	Familiarity with SMR Technology	Proximity to Site/Relevance to Jurisdiction
5	Many years of experience operating SMR units of the same technology.	Excellent relative ESG performance, high degree of transparency. No accidents/ controversy affecting the track record.	Significant government backing and the cost of SMR deployment can be covered by 10% of previous revenue.	Has operated the SMR design under consideration for same/ similar application.	Has experience operating in the same jurisdiction as the proposed site.
4	5+ years of experience operating similar reactors.	Good relative ESG performance and high degree of transparency. No accidents/ controversy affecting the track record.	Moderate government backing and the cost of SMR deployment can be covered by 20% of previous revenue.	Has operated the SMR design under consideration for different application.	Has experience operating in the same country as the proposed site.
3	5+ years of nuclear operating experience.	Satisfactory relative ESG performance. Minor accidents/ controversy affecting the track record.	Low government backing and the cost of SMR deployment cost can be covered by 50% of previous revenue.	Has operated a different SMR design under consideration for a similar application.	Has experience operating in a neighboring ally country as the proposed site.
2	Some experience operating a NPP.	Poor relative ESG performance. Minor accidents/ controversy affecting the track record.	No government backing and the cost of SMR deployment cost can be covered by 75% of previous revenue.	Has operated a different SMR design under consideration for a different application.	Has experience operating in ally country of the proposed site.
1	No nuclear operating experience.	Poor relative ESG performance. Accidents/ controversy affecting the track record.	Licensee/Operator is seeking funding, highly restricted budget.	Has no experience with the SMR technology.	Has OPEX in countries with unstable political relations with country of the proposed site.

Technology Vendor						
Readiness Level	Technology Development Status	Regulatory Approval Status in Canada	Corporate Structure	Financial Strength	Quality Assurance	Pedigree
5	TRL 9	Vendor has commercial sites licensed with years of operation.	Vendor has defined hierarchy, functional divisions, and roles. 1000+ people.	Proven history of revenue, long term financial stability and strength.	QA Program in place and success history applying QA to all relevant activities.	Established as NPP supplier that has successfully delivered projects.
4	TRL 7 to 8	Vendor has prototype site licensed and is ready for construction of a commercial site.	Vendor has a defined hierarchy, functional divisions, and 500+ people.	Vendor has revenue generation from products and services.	QA Program fully developed and partially applied to activities.	Developed designs for local/ domestic deployment.
3	TRL 5 to 6	Vendor's Environmental Preliminary Safety Assessment, is completed.	Vendor organization has a defined hierarchy, functional divisions, and 100+ people.	Vendor has significant investment commitments or development spend	QA Program partially developed and partially applied to activities.	Have designed and deployed non-commercial nuclear reactors.
2	TRL 3 to 4	Vendor is currently in the Vendor Design Review process.	Vendor has business Functional roles and structures in place, hires employees.	Vendor has seed money in the bank, venture capitalists, loans, etc.	Vendor has a QA Program development plan in place.	New entrant into reactor design space and a few years of experience.
1	TRL 1 to 2	Vendor has had only an initial discussion with CNSC or none.	Vendor is a corporation; with defined roles, and a growth plan.	Vendor is seeking funding, highly restricted budget.	Vendor has no defined QA program.	No nuclear experience.

EPC/EPCM Partners						
Readiness Level	Level of Engagement	Scope of EPC/EPCM Capabilities	Corporate Structure & Financial Strength	Delivery Capability	Resource Pool	Track Record
5	Deep, secure partnerships. The contracts are large and have been in place for multiple years.	Partners capable of contributing to all phases of deployment.	Partner(s) are well organized, 1000+ people and a history of long-term financial strength.	Able to deploy resources at site readily. Has multidisciplinary in-house capabilities.	Has delivered >80% of nuclear projects on time and schedule.	Deep, secure partnerships. The contracts are large and have been in place for multiple years.
4	Strong partnerships. The contracts are large, and implementation is well underway.	Partners capable of contributing to nearly all phases of deployment.	Partner(s) are well organized, 500+ people and generate revenue	Able to deploy resources at site readily. Can procure multi-disciplinary capability as necessary.	Has delivered >60% of nuclear projects on time and schedule.	Strong partnerships. The contracts are large, and implementation is well underway.
3	Strong partnerships. The contracts are (semi) large and implementation is underway.	Partners capable of contributing to some phases of deployment	Partner(s) are well organized, 100+ people and have significant investments in the reactor build.	Able to deploy resources at site readily. Can procure multidisciplinary. capability as required.	Has delivered >50% of nuclear projects on time and Schedule.	Strong partnerships. The contracts are (semi) large and implementation is underway.
2	Non-binding partnerships. The contracts are moderate in scope.	Partners capable of contributing to 1 phase of deployment (likely design).	Partner(s) have a thin organizational structure and have seed money.	Able to deploy resources at project site. May be able to procure Multi-disciplinary capability.	Has delivered <40% of nuclear projects on time and schedule.	Non-binding partnerships. The contracts are moderate in scope.
1	No meaningful partnerships, little/no evidence of contribution from EPC/EPCM partners.	Partners unable to meaningful contribute to any phase of development	Partner(s) are a corporation with a growth plan operating on a highly restricted budget.	Unable to deploy resources at project site. Cannot procure multi-disciplinary capability.	Has delivered some projects on time and schedule, Unreliable track record.	No meaningful partnerships, little/no evidence of contribution from EPC/EPCM partners.

Appendix J:
Economic Impact Model Background

Economic Impact Model Background

Broadly speaking, input-output multipliers measure the relationship between an initial shock (such as spending) and final outcomes across the whole of the economy in terms of gross output, GDP, and employment. This study uses “Type II” multipliers.

Type II multipliers allow for both the “indirect” supply chain effects (i.e., construction or manufacturing industry purchasing from other industries) and “induced” effects which arise from workers spending wages (derived from employment) on goods and services. (Studies which only allow for the indirect or supply chain effects use what are known as Type I multipliers. Type II multipliers will be larger than Type I multipliers.)

Input-output modeling focuses on the interrelationships of sales and purchases among sectors of the economy. It is best understood through its most basic form, the interindustry transactions table or matrix. In this table (see Table J-1 for an example), the column industries are consuming sectors (or markets), and the row industries are producing sectors. The content of a matrix cell is the value of shipments that the row industry delivers to the column industry. Conversely, it is the value of shipments that the column industry receives from the row industry. Hence, the interindustry transactions table is a detailed accounting of the disposition of the value of shipments in an economy.

Table J-1: Interindustry Transaction Matrix (Values)

	Agriculture	Manufacturing	Services	Other	Final Demand	Total Output ($)
Agriculture	10	65	10	5	10	100
Manufacturing	40	25	35	75	25	200
Services	15	5	5	5	90	120
Other	15	10	50	50	100	225
Value Added	20	95	20	90		
Total Input	100	200	120	225		

For example, in Table J-1, agriculture, as a producing industry sector, is depicted as selling $65 of goods to manufacturing. Conversely, the table depicts that the manufacturing industry purchased $65 of agricultural production. The sum across columns of the interindustry transaction matrix is called the intermediate outputs vector. The sum across rows is called the intermediate inputs vector.

A single final demand column is also included in Table J-1. Final demand, which is outside the square interindustry matrix, includes imports, exports, government purchases, changes in inventory, private investment, and sometimes household purchases.

The value-added row, which is also outside the square interindustry matrix, includes wages and salaries, profit-type income, interest, dividends, rents, royalties, capital consumption allowances, and taxes. It is called value added because it is the difference between the total value of the industry's production and the value of the goods and nonlabor services that it requires to produce. Thus, it is the value that an industry adds to the goods and services it uses as inputs to produce output. The value-added row measures each industry's contribution to wealth accumulation. In a national model, therefore, its sum is better known as the gross domestic product (GDP).

Input-output economic impact modelers now tend to include the household industry within the square interindustry matrix. In this case, the "consuming industry" is the household itself. Its spending is extracted from the final demand column and is appended as a separate column in the interindustry matrix. To maintain a balance, the income of households must be appended as a row. The main income of households is labor income, which is extracted from the value-added row. Modelers tend not to include other sources of household income in the household industry's row. This is not because such income is not attributed to households but rather because much of this other income derives from sources outside of the economy that is being modeled.

The first step in producing input-output multipliers is to calculate the direct requirements matrix, which is also called the technology matrix. The calculations are based entirely on data from Table J-1. As shown in Table J-2, the values of the cells in the direct requirements matrix are derived by dividing each cell in a column of Table J-1, the interindustry transactions matrix, by its column total. For example, the cell for manufacturing's purchases from agriculture is 65/200 = .33. Each cell in a column of the direct requirements matrix shows how many cents of each producing industry's goods and/or services are required to produce one dollar of the consuming industry's production and are called technical coefficients. The use of the terms "technology" and "technical" derive from the fact that a column of this matrix represents a recipe for a unit of an industry's production. It, therefore, shows the needs of each industry's production process or "technology."

Table J-2: Direct Requirements Matrix

	Agriculture	Manufacturing	Services	Other
Agriculture	0.10	0.33	0.08	0.02
Manufacturing	0.40	0.13	0.29	0.33
Services	0.15	0.03	0.04	0.02
Other	0.15	0.05	0.42	0.22

Next in the process of producing input-output multipliers, the Leontief Inverse is calculated. The Leontief Inverse portrays the relationships between final demand and production. Because it does translate the direct economic effects of an event into the total economic effects on the modeled economy, the Leontief Inverse is also called the total requirements matrix. The total requirements matrix resulting from the direct requirements matrix in the example is shown in Table J-3.

Table J-3: Total Requirements Matrix

	Agriculture	Manufacturing	Services	Other
Agriculture	1.50	0.59	0.44	0.31
Manufacturing	0.96	1.57	0.88	0.72
Services	0.27	0.14	1.15	0.10
Other	0.50	0.29	0.76	1.45
Industry Multipliers	3.23	2.58	3.23	2.58

In the direct or technical requirements matrix in Table J-1, the technical coefficient for the manufacturing sector's purchase from the agricultural sector was .33, indicating the 33 cents of agricultural products must be directly purchased to produce a dollar's worth of manufacturing products. The same "cell" in Table J-3 has a value of .6. This indicates that for every dollar's worth of product that manufacturing ships out of the economy (i.e., to the government or for export), agriculture will end up increasing its production by 60 cents. The sum of each column in the total requirements matrix is the output multiplier for that industry.

Generally, when domestic demand expands there will also be an increase in the demand for imports. For example, if consumers spend money in the construction industry some of this spending will flow out of the country (e.g., due to the purchase of imported materials by construction companies). This is formally known as "leakage". Allowing for leakage is important as otherwise the contributions on domestic demand will be overestimated. To account for the leakage, we adjusted both the Ontario and National IO data by the ratio of the regional production to total demand.

In addition to the indirect impacts, the Type II multipliers used in this study also include the impacts associated with the spending of the wages and salaries paid to the direct and indirect employees. To account for the fact that not all the wages and salaries will be spent – some will be saved, and some will go to pay for taxes, we reduce the wages and salary row. Research from the Montreal Economic Institute found that the average Canadian family paid 42% of their income in taxes to various levels of government[134] and the saved around 10% of their income.[135] To account for this, we adjusted the wages and salary line of the IO data.

The IO data is based on gross output and as such, the resulting multipliers are for gross output. We calculated gross value add (GDP) multipliers by using sectoral ratios of value added to gross output estimated from the IO tables. We also developed employment multipliers[136] using sectoral productivity (measured in terms of GDP per worker) and wage and salary multipliers using sectoral ratios of wages and salaries estimated from the IO tables. This allowed us to estimate output, gross value add, employment, and wage and salary multipliers for each industry.

134 Report: Canadian tax burden outweighs spending on essentials | Wealth Professional.

135 Finder reveals just how much Canadians' household savings grew in 2020 (mortgagebrokernews.ca).

136 Labour productivity and related measures by business sector industry and by non-commercial activity consistent with the industry accounts (statcan.gc.ca).

In addition to the economic impact multipliers, we also developed production and product tax multipliers using sectoral ratios of production and product taxes to gross output estimated from the IO tables.

The multipliers used in this analysis were calculated using interindustry transactions matrix and industry employment data for Ontario[137] and Canada[138] obtained from Statistics Canada[139] for 2019. The interindustry transactions matrix included 234 sectors, but for the purposes of this analysis, we combined some closely related industries together, resulting in 208 sectors being included in the model.

Since the input/output and employee productivity data are from 2019, the model inputs need to be deflated to 2019 before estimating the resulting direct, indirect, and induced employment estimates. The direct spending data was deflated using CPI data obtained from Statistics Canada.[140]

[137] Provincial Symmetric Input/Output Tables: https://www150.statcan.gc.ca/n1/en/catalogue/15-211-X.
[138] National Symmetric Input/Output Tables: https://www150.statcan.gc.ca/n1/en/catalogue/15-207-X.
[139] Statistics Canada: Canada's national statistical agency (statcan.gc.ca).
[140] https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000501.


HATCH