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Deployability of Small Modular Nuclear Reactors for Alberta Applications – Phase II

Report Prepared for Alberta Innovates

March 2018

SM Short
BE Schmitt

U.S. DEPARTMENT OF ENERGY
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Pacific Northwest National Laboratory
Richland, Washington 99352

Executive Summary

At present, the steam and electricity requirements of Alberta's oil sands industry are predominantly met by natural gas. On November 22, 2015 the Government of Alberta announced its Climate Change Leadership Plan to reduce greenhouse gas emissions that cause climate change. Two major aspects of this plan specifically relevant to oil sands operations are: 1) capping oil sands emissions to 100 megatonnes of carbon dioxide equivalent per year and 2) putting a price on greenhouse gas (GHG) emissions. Small modular nuclear reactors (SMRs) could potentially play a role in providing competitively-priced, environmentally-acceptable, and dependable/reliable heat, power, and hydrogen for oil sands operations in order to meet the goals of the Climate Change Leadership Plan.

In support of this goal, Alberta Innovates (AI) contracted with Pacific Northwest National Laboratory (PNNL) to provide a realistic assessment of the current state of development, and the potential for further development, of SMRs and their prospective application in Alberta for producing GHG emissions-free steam, electricity, and hydrogen for Alberta oil sands operations. In Phase I of this study (PNNL 2016), 26 SMR technologies were evaluated and ranked for their technical applicability and viability to service the energy needs of a steam-assisted gravity drainage (SAGD) facility. [Note: Appendix A of this report briefly summarizes promising new SMR concepts (i.e., TerraPower traveling wave reactor) that have emerged since that study.] The Phase I study also briefly considered SMRs used in marine/naval vessels. While there is significant operational history with these types of SMRs, important design features generally make them impractical for use as commercial, land-based SMRs. For example, a common design feature of marine/naval vessels is the use of high-enriched uranium (HEU)[1] fuel that is not available for commercial applications. SMR designs based on marine/naval SMR designs are not generally being pursued by reactor vendors for commercial applications. The Phase I study did, however, consider Russian SMR design concepts that are based on their marine/naval reactor designs (e.g., RITM-200, SVBR-100).

In this Phase II study, the Phase I assessment is expanded to also evaluate SMR technologies to reduce GHG emissions from surface mining of bitumen and bitumen upgrading facilities, in addition to an expanded assessment of SMR application to SAGD facilities. The key objectives of the Phase II study are as follows: 1) to provide a techno-economic assessment of SMRs for applications in SAGD, surface mining, and hydrogen production in the oil sands, to displace the incumbent natural gas-based technologies, and thereby reduce GHG emissions associated with steam, electricity and hydrogen production, 2) to identify opportunities for cost reductions associated with SMRs that would facilitate increased cost-competitiveness against natural gas, and 3) to contextualize the non-technical deployment challenges of SMRs in Alberta, including regulatory, human capital, used fuel and radioactive waste, supply chain, and logistical hurdles.

The intent of this report is to provide intelligence to AI regarding the potential for SMR applications in the Alberta oil fields, using publicly-available information. Neither the commissioning of this study, or

[1] HEU fuel is defined as having a Uranium-235 (U-235) content greater than or equal to 20% while LEU fuel is defined as having a U-235 content less than 20%. None of the SMR concepts evaluated in the Phase I study used HEU fuel.

the release of this report, imply that the authors, PNNL, AI, or its collaborators advocate the development or deployment of SMRs.

Alberta Oil Sands Surface Mining of Bitumen Application

For this application a reference surface mining facility was defined having a bitumen production capacity of 200,000 barrels per day (bbl/d) utilizing either paraffinic or naphthenic froth treatment in the bitumen extraction process. The 26 SMRs evaluated in the Phase I report were evaluated and a reference SMR(s) was selected based on several factors. Principal among these factors were the technical capability of the technology to provide the electricity and process steam requirements for the reference facility, which are defined in Table 2-1 of this report, and the technology readiness level (TRL) or expected availability of the SMR technologies to provide timely support to the Government of Alberta Climate Change Leadership Plan goals to limit greenhouse gas emissions from oil sands operations.

Integral pressurized water reactor (iPWR) technology was selected as the reference SMR technology for the oil sands mining and extraction facility application for the following reasons: (1) iPWRs can readily be integrated into the reference facility material and process flowsheets to produce the electricity and process steam requirements of the reference facility, (2) iPWR technology is based on PWR technology that is utilized extensively for electricity production, which has over 50 years of operating experience representing thousands of reactor years of operation and is generally not a significant technology evolution from standard PWR technology, and (3) iPWR vendors are making substantial investments in the technology, thereby supporting the expectation of their relatively near-term availability.

The NuScale iPWR and the SMART iPWR were selected as the reference iPWRs because (1) the respective vendors are making significant investments in the technology, 2) the designs are well advanced and either have completed or are currently undergoing review by the national nuclear regulator of the respective countries where the technology was developed (i.e., U.S. and South Korea, respectively), and 3) there is generally a sufficient level of publicly-available information on these technologies to support their evaluation in this study. However, the reader is cautioned that these iPWR designs, like all of the iPWR designs, are still in the development phase and so there is no practical experience with the construction and operation of these evolutionary PWR designs.

For this evaluation, the reference iPWRs were assumed to completely replace the gas turbine generators (GTGs) and associated systems in the reference surface mining facility to cogenerate the required process steam and electricity. While development of detailed mass and energy balance flow sheets with incorporation of the reference iPWRs was beyond the scope of this project, best estimates were made of the number of NuScale and SMART modules needed to produce the electricity and steam consumed in the reference facility based on published technology-specific design parameters. The number of NuScale modules was estimated to range from six to eight, while the number of SMART modules ranged from three to four.

Since no nuclear power reactors have been built or operated to-date using iPWR technology, there are no historical costs to report on this evolutionary technology. Hence, this study relied on published estimates by iPWR vendors, with a specific focus on cost estimates that had published information on the underlying basis for the estimates and which provided sufficient breakdown of the cost estimate to draw insights on the significant cost contributors. Three types of cost estimates for iPWRs are developed based on the vendor-specific data and reported in this study: 1) overnight engineering, procurement, and construction (EPC) cost (cost/kilowatt electric or kWe), which is the cost of a construction project if no interest was incurred during construction and 2) levelized cost of electricity, or LCOE (cost/megawatt-hour or MW-hr), which is the cost of building, operating, and decommissioning the plant over an assumed financial life, and 3) levelized cost of steam, or LCOS (cost/tonne steam), which is the LCOE multiplied by a design-specific conversion factor (MW-hr/tonne steam). While the oil sands surface mining facility iPWR application is not solely an electricity generation project (production of process steam is also a need), LCOE is used as a figure-of-merit in this study because of its common usage in comparing the cost of different types of electricity generation technologies, including the GTG technology that is utilized in the reference surface mining facility.

To develop overnight EPC costs, LCOE, and LCOS, cost estimates published by the vendors for the two reference iPWR technologies (which were in U.S. dollars) were first escalated to a common base year and then converted to Canadian dollars using an "average" exchange rate between the two currencies for that base year. The overnight EPC cost for an iPWR plant is estimated to be in the range of C$5,600-7,300/kWe (2014) depending on the iPWR technology and the number of modules per plant. Insufficient information was available to determine the LCOE for the SMART plant. The LCOE for a NuScale plant, assuming a 40 year operating life[2], is estimated to be in the range of C$125-136/MW-hr (2014) (or C$24.7-26.8/tonne steam), again depending on the iPWR technology and number of modules per plant. For comparison, an SMR industry organization in the U.S. recently estimated the LCOE for the first SMR to be C$130/MW-hr (2017) for an investor-owned plant and the overnight EPC cost to be C$5,750/kWe (2017), after conversion from U.S. dollars, with the expectation that these costs will decrease as additional SMRs are built (SMR Start 2017). These estimates are similar to those estimated in this study for iPWR SMRs.

Comparatively, the overnight EPC cost of a natural gas cogeneration plant is estimated to be about C$1750/kWe (2014), which is substantially less than that of an iPWR. Estimates of the LCOE of using natural gas cogeneration in the oil sands application range from about C$80-95/MW-hr (2014), which includes an assumed carbon or GHG price of C$30/tonne CO_2. On this basis, the cost of iPWR technology is estimated to be higher than natural gas cogeneration by C$30-60/MW-hr (2014).

Figure ES-1 provides a "representative" breakdown of the LCOE cost for both iPWR and natural gas cogeneration.[3] The intent of this figure is to provide a relative comparison of the two technologies for the purpose of identifying the major reasons for the differences between the two. To develop this figure,

[2] The assumption of a 40 year life is a standard assumption when comparing different power generation sources. This is a conservative assumption because SMRs are generally being designed to operate for 60 years or longer. Hence, assuming an operating life of more than 40 years would improve the economics of the SMR technologies relative to GTG technologies as reported in this study.

[3] The term "representative" is used to denote a single point estimate of the LCOEs for iPWR and natural gas cogeneration technologies using the same LCOE formula for both technologies. The ranges of LCOEs reported elsewhere in this report were generally developed in the respective references cited for these estimates, and escalated to a common year and/or converted to Canadian currency as necessary, and so reflect different assumptions in the LCOE estimates. The "representative" estimates were developed using common assumptions, such as the same LCOE formula, tax rate, discount rate, etc., based on available information. For this reason, the total LCOEs reported in Figure ES-1 for both iPWR and natural gas cogeneration are somewhat different (lower) than those developed from the cited references.

component costs for natural gas cogeneration (CESAR 2014) and component costs for a generic SMR (SMR Start 2017) were used to develop the LCOE using the CESAR LCOE formula (CESAR 2014). Hence, the costs reported in this figure are somewhat different than those reported above. The most significant reason for the difference in LCOE between the two technologies is the significantly higher capital cost of iPWR plants compared to that for cogeneration plants. The operating cost of an iPWR (excluding fuel) is also significantly higher than that for a cogeneration plant, however, this is largely offset by a much higher fuel cost for the cogeneration plant than for an iPWR plant.

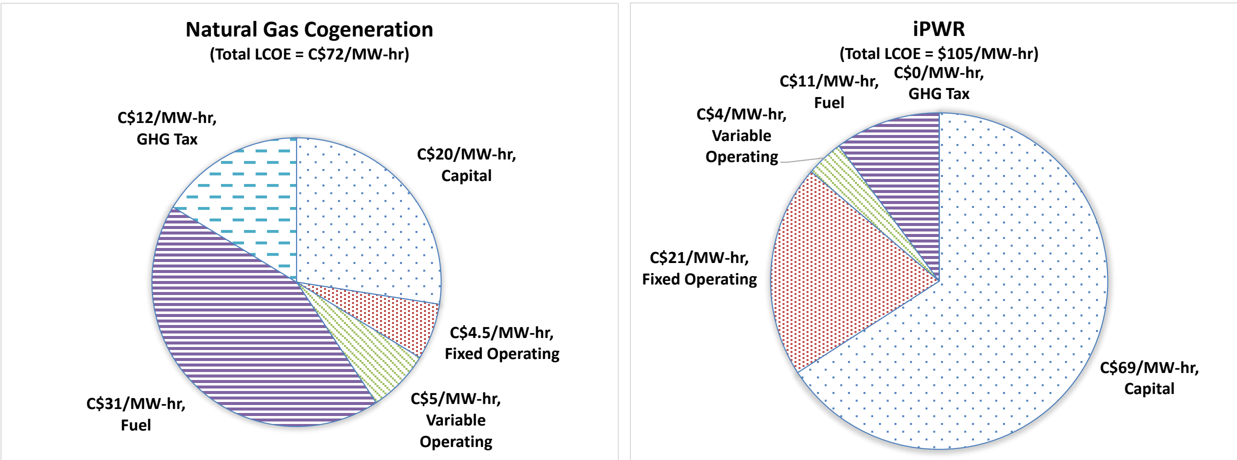

Figure ES-1. Comparison of Representative LCOE (2017) for iPWR and Natural Gas Cogeneration

Improving the economic competitiveness of iPWRs relative to natural gas cogeneration for the oil sands surface facility application is a significant challenge with today's natural gas prices that are near historical lows, and which are expected to stay low for the foreseeable future (this analysis assumes a natural gas price of C$3.25/GJ). Assuming no reductions or improvements in the cost of iPWRs, it is estimated that the price of natural gas would have to increase to C$7.5-8.0/GJ for iPWRs to become economically competitive with natural gas cogeneration. Several considerations for reducing the cost of iPWRs, based on the most significant cost contributors, include:

- The largest single contributor to the LCOE for an iPWR is the initial capital investment to construct/commission the plant and the associated cost of financing. The LCOE for an iPWR can be reduced by 30% or more by obtaining better financing conditions (e.g., municipality-type financing rather than private investment financing, government loan guarantees). In addition, reducing the construction/commissioning schedule for the iPWR plant would reduce financing costs incurred prior to plant operation, which can be substantial.

- The overnight EPC cost of an iPWR plant is three to four times higher than that for a natural gas cogeneration plant. A breakdown of the overnight EPC cost for an iPWR plant is provided in Figure ES-2. The EPC cost for the reactor modules and associated reactor/containment building or nuclear island contribute about 50% of the total EPC cost of the reference iPWR. Reducing the overnight EPC cost by 20% (e.g., deploying multiple plants to obtain economies, government-backed supply chain) would decrease the LCOE by about 9%.

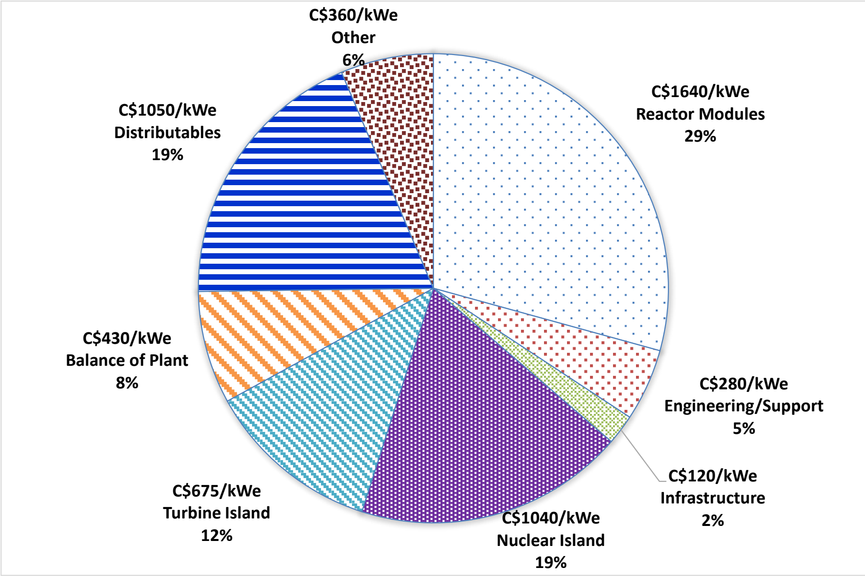

Figure ES-2. Overnight EPC Cost (2014) of an iPWR Plant (C$5600/kWe)

- O&M and security staff levels are estimated to contribute about 50% of the total plant operating staff estimate of 250-310 FTEs for the reference iPWR. This is high relative to the staffing level of 50-60 FTEs required to operate a typical natural gas cogeneration plant. If staffing levels were reduced by 50% (e.g., increased automation of control and monitoring systems, decreased labor requirements due to passive safety/security features), the LCOE would decrease by about 4%.

- The cost of the reference iPWR is for a plant that utilizes all of the produced steam to generate electricity. However, for a surface mining facility, only about half of the plant is needed to generate electricity, while the superheated steam for the remaining half is used to generate process steam required for the surface mining facility operations. Hence, the turbine-generator plant only needs to be half the size assumed in the LCOE estimate. On the other hand, this reduced equipment requirement is offset by the need for other equipment/systems (steam heaters or reboilers) to convert the superheated steam to saturated process steam having the appropriate pressure and temperature conditions. Estimating the cost difference between these two facility configurations was beyond the scope of this study, however, if the overnight EPC cost of the turbine island is reduced by 50%, the LCOE would decrease by about 3%.

- Distributables (Temporary Buildings, Field Staff, Construction Equipment, etc.) are estimated to be about 19% of the overnight EPC cost of the reference iPWR plant. Since the oil sands mining and extraction facility is a large industrial facility, it may be possible to reduce the cost of distributables by sharing some of these costs with the surface mining facility. If the overnight EPC cost of distributables is reduced by 50%, the LCOE would decrease by about 4%.

- Severe accidents, such as those at the Three Mile Island Unit 2 plant in 1978 and the Fukushima Daiichi plant in 2011, have raised public awareness of the potential risks with nuclear power.

These accidents demonstrated that under extreme conditions, the nuclear fuel will fail resulting in severe damage to the plant and, potentially, the release of large quantities of radioactive material. Recognizing the vulnerability of current LWR fuel designs to severe accident conditions, there is considerable on-going world-wide research into developing advanced fuel designs that are more accident-tolerant than the current fuel designs. The iPWRs evaluated in this study have already incorporated many innovative design features to significantly reduce the likelihood of a severe accident relative to that of current generation LWRs. However, the use of advanced accident-tolerant fuel designs could further improve the safety and the economics of LWRs, including SMRs.

Alberta Oil Sands In-situ Recovery (SAGD) Application

For this application a reference facility was defined having a bitumen (dilbit) production capacity of 33,000 bbl/d. Approximately 90% of the GHG emissions associated with SAGD oil sands extraction are due to natural gas consumption. Similar to the iPWR evaluation, the 26 SMRs evaluated in the Phase I report were evaluated and a reference SMR(s) was selected based on several factors. Principal among these factors were the technical capability of the technology to provide the high temperature steam requirements for the reference facility, which are defined in Table 3-1 of this report, and the TRL or expected availability of the SMR technologies to provide timely support to the Government of Alberta Climate Change Leadership Plan goals to limit greenhouse gas emissions from oil sands operations.

HTGR technology was selected as the reference SMR technology for the SAGD facility application for the following reasons: (1) HTGRs can readily be integrated into the reference facility material and process flowsheets to produce the high temperature steam (and electricity) requirements of the reference facility, (2) while iPWR technology is based on PWR technology that has over 50 years of operating experience representing thousands of reactor years of operation, it is not directly suitable for producing the high pressure steam required for the SAGD application, (3) while HTGR technology is not currently in any operating nuclear power plant, there is a significant amount of design and operational experience with HTGR technology (unlike with most other advanced reactor technologies), and (4) HTGR vendors are making significant investments in the technology supporting the expectation of their availability within the next several years.

The SC-HTGR SMR and the StarCore SMR were selected as the reference HTGRs because 1) the StarCore HTGR concept ranked the highest in the Phase I report (PNNL 2016) for SAGD application in the Alberta oil sands and 2) of the HTGR design concepts, the SC-HTGR design has the most comprehensive information available in the open literature on the design, including details on preliminary estimates of its economics and staffing levels. However, the reader is cautioned that these HTGR designs, like all of the HTGR designs, are still in the development phase and so there is no practical experience with the construction and operation of these next generation HTGR designs.

For this evaluation, the reference HTGRs were assumed to completely replace the gas-fired once through steam generators (OTSGs) to generate the required high and low pressure steam, with specific focus on generating the high pressure steam. While development of detailed mass and energy balance flow sheets with incorporation of the reference HTGRs was beyond the scope of this project, best estimates were made of the number of SC-HTGR and StarCore modules needed to produce the high temperature steam consumed in the reference facility based on published technology-specific design parameters. One SC-

HTGR module was estimated to be sufficient to generate the required high temperature steam, while 18 StarCore modules were estimated to be required.

It has been over 25 years since a nuclear power plant using HTGR technology has operated anywhere in the world (although there are research/demonstration reactors using HTGR technology currently operating), and none of the HTGR SMRs discussed in the Phase I report (PNNL 2016) have yet been built or operated (although construction of the two unit demonstration HTR-PM HTGR in China is nearing completion and startup is expected in Spring 2018). Hence, there are no recent historical costs available on this technology. This study therefore relies on published estimates of the cost of HTGR technology, with a specific focus on cost estimates that have published information on the underlying basis for the estimates and which provide sufficient breakdown of the cost estimate to draw insights on the significant cost contributors. As with iPWRs, overnight EPC cost (cost/kWe), LCOE (cost/MW-hr), and LCOS (cost/tonne steam) are utilized in this study for the cost of HTGRs. While the oil sands SAGD HTGR application is mostly for process steam production (electricity generation is a minor need), LCOE is used as a figure-of-merit in this study because of its common usage in comparing the cost of different types of electricity generation technologies and because this is the metric used in a recently completed study evaluating replacing the OTSGs with cogeneration GTGs having heat recovery steam generators (HRSGs).

The overnight EPC cost for a single-module SC-HTGR plant is estimated to range from C$4,600-9,870/kWe (2014), with a best estimate of C$6,580/kWe (2014). The LCOE for a single-module SC-HTGR plant is estimated to range from C$110-180/MW-hr (2014) (or C$30-50/tonne steam), with a best estimate of C$140/MW-hr (2014) (or C$37/tonne steam). No estimate for the overnight EPC cost or the LCOE is available for the StarCore HTGR.

Comparatively, as discussed in the previous section, the overnight EPC cost of a natural gas cogeneration plant is estimated to be about C$1750/kWe (2014), which is substantially less than that of an HTGR. Estimates of the LCOE of using natural gas cogeneration in the oil fields SAGD application range from about C$80-C$95/MW-hr (2014), which includes an assumed carbon or GHG price of C$30/tonne CO_2. On this basis, the cost of HTGR technology is estimated to be higher than natural gas cogeneration by C$15-100/MW-hr (2014), with a best estimate of about C$50/MW-hr (2014).

Figure ES-3 provides a "representative" breakdown of the LCOE cost for both HTGR and natural gas cogeneration.[4] As with iPWR technology discussed previously, the capital cost of an HTGR plant is significantly higher than that for cogeneration plants. The operating cost of an HTGR (excluding fuel) is also significantly higher than that for a cogeneration plant, however, this is somewhat offset by a higher fuel cost for the cogeneration plant.

[4] The term "representative" is used to denote a single point estimate of the LCOEs for HTGR and natural gas cogeneration technologies using the same LCOE formula for both technologies. The ranges of LCOEs reported elsewhere in this report were generally developed in the respective references cited for these estimates, and escalated to a common year and/or converted to Canadian currency as necessary, and so reflect different assumptions in the LCOE estimates. The "representative" estimates were developed using common assumptions, such as the same LCOE formula, tax rate, discount rate, etc., based on available information. For this reason, the total LCOEs reported in Figure ES-3 for both HTGR and natural gas cogeneration are somewhat different (lower) than those developed from the cited references.

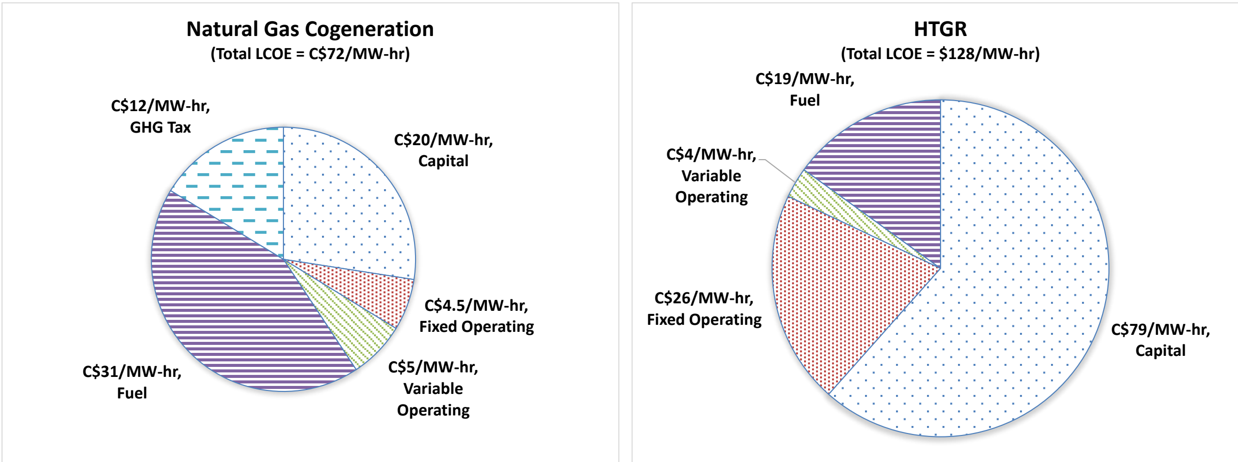

Figure ES-3. Comparison of Representative LCOE (2014) for HTGR and Natural Gas Cogeneration

Improving the economic competitiveness of HTGRs relative to natural gas cogeneration for the oil sands SAGD application has similar challenges to those discussed previously for the iPWR (as discussed previously, this analysis assumes a natural gas price of C$3.25/GJ). Assuming no reductions or improvements in the cost of HTGRs, it is estimated that the price of natural gas would have to increase to C$10.5-11.0/GJ for HTGRs to become economically competitive with natural gas-fired OTSGs. Several considerations for reducing the cost of HTGRs, based on the most significant cost contributors, include:

The largest single contributor to the LCOE for an HTGR is the initial capital investment to construct/commission the plant and the associated cost of financing. The LCOE for an HTGR can be reduced by 30% or more by obtaining better financing conditions (e.g., municipality-type financing rather than private investment financing, government loan guarantees). In addition, reducing the construction/commissioning schedule for the HTGR plant would reduce financing costs incurred prior to plant operation, which can be substantial.

- The overnight EPC cost of an HTGR plant is three to six times higher than that for a natural gas cogeneration plant. A breakdown of the overnight EPC cost for an HTGR plant is provided in Figure ES-4. There is significant uncertainty in the EPC cost of HTGR SMRs because HTGRs have not been deployed for commercial (electricity generation) application in almost 30 years (current operating HTGRs are research/demonstration reactors). If the EPC cost were reduced by 25%, the LCOE would decrease by about 15%.

- O&M and security FTEs are estimated to contribute about 70% of the total plant operating staff estimate of 166 FTEs for the reference HTGR. This is high relative to the staffing level of 50-60 FTEs required to operate a typical natural gas cogeneration plant. If staffing levels were reduced by 50% (e.g., increased automation of control and monitoring systems, increased credit for passive security features), the LCOE would decrease by about 4%.

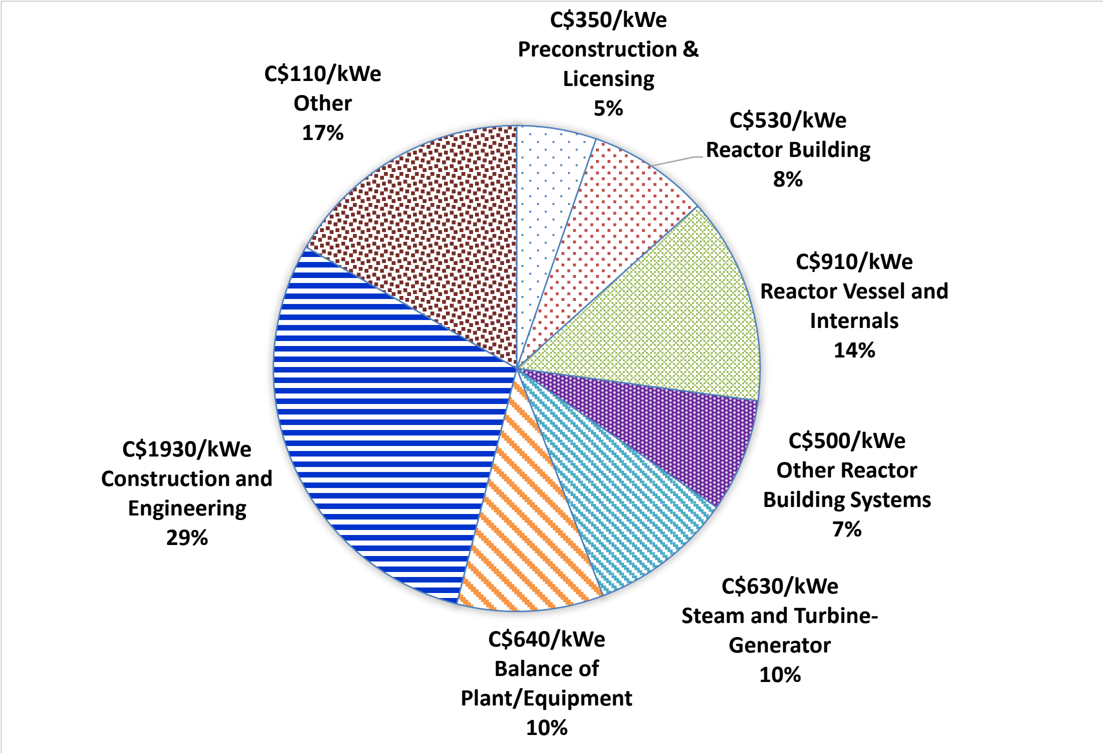

Figure ES-4. Overnight EPC Cost (2014) of an HTGR Plant (C$6600/kWe)

- The cost of the reference HTGR is for a plant that utilizes all of the produced steam to generate electricity. However, the plant is mostly needed to generate process steam. Hence, the turbine-generator plant is not needed, representing about 10% of the capital cost that could be substantially reduced. On the other hand, this reduced requirement is offset by the potential need for other equipment/systems (steam heaters or reboilers) to convert the superheated steam to saturated process steam having the appropriate pressure and temperature. If the overnight EPC cost of the turbine island is reduced by 80%, the LCOE would decrease by about 9%.

- Construction and engineering (or distributables) are estimated to be about 29% of the overnight EPC cost of the reference HTGR plant. Since the oil sands SAGD facility is part of a large industrial facility, it may be possible to reduce the cost of distributables by sharing these costs with the SAGD and associated facilities. If the overnight EPC cost of distributables is reduced by 50%, the LCOE would decrease by about 10%.

Alberta Oil Sands Hydrogen Production for Bitumen Upgrading Application

For this application a reference bitumen upgrading facility is assumed to be sized to support upgrading of the bitumen product from the reference surface mining facility, which has a production rate of 200,000 barrels per day (bbl/d). The hydrogen production rate required to upgrade the bitumen is assumed to be 3.4 kg/bbl (Olateju 2016). About one third of bitumen upgrading emissions are due to hydrogen production, predominantly from natural gas. While electricity is also consumed in the bitumen upgrading process, this study was limited to assessing the potential for SMR technology to generate the hydrogen (H_2) required, which is defined in Section 4.0 of this report, for the upgrading process.

Hundreds of methods have been postulated for separating hydrogen from the large number of compounds to which it is attached. However, a comprehensive review of all of these methods was beyond the scope of this study. This study therefore relied on previous nuclear industry assessments that evaluated a multitude of methods for producing hydrogen with nuclear power, to identify those that are most promising for efficient, cost-effective, large-scale production of hydrogen, and which are most actively being investigated today. Because the purpose of this study is to evaluate the potential to use SMRs to reduce GHG emissions in oil sands operations, hydrogen production methods that result in GHG emissions are not considered. Four hydrogen production methods that have garnered the most attention over the last 10 years were evaluated.

Low Temperature Electrolysis (LTE). LTE is a water-splitting process that decomposes water into its basic elements at standard temperature and pressure. In this process H_2 is produced from electrolysis by passing a direct electric current, with the aid of an electrolyte, through water to decompose the water molecules into hydrogen (H_2) and oxygen (O_2). It is a fairly common method for producing hydrogen today, but not generally in industrial-scale quantities, as is required for the oil sands application, due to the large amount of electricity required to decompose the water and the inefficiency of the process. Because an electric current is what drives the decomposition reaction, any SMR technology can be used to generate the electricity used in the process.

iPWR technology was selected as the reference SMR technology for integration with LTE technology to produce hydrogen. This selection was based on the same considerations as discussed previously for selection of iPWR technology for the oil sands mining and extraction application, and because electricity is the only energy source required to drive hydrogen production with LTE technology. The electrical generation capacity needed to produce the hydrogen required for the reference bitumen upgrading facility is estimated to be 1510 to 2450 MWe, depending on the efficiency of the electrolysis process. The number of iPWR modules needed to provide this electrical energy requirement ranges from 34 to 55 NuScale iPWR modules or 15 to 25 SMART iPWR modules. Deployment of these large numbers of modules for the bitumen upgrading application is not feasible or cost effective and so is not considered further in this report. However, research is continuously improving the efficiency, or reducing the electricity usage, of electrolyzers. Based on this, it is recommended that improvements in LTE technology be reconsidered should use of SMR technology for hydrogen production be pursued.

High temperature steam electrolysis (HTSE). HTSE is similar to LTE except that it achieves a higher efficiency by operating at higher temperatures. Specifically, high temperature steam up to 950°C, rather than liquid water as in LTE, is decomposed. The HTSE process has been the focus of significant research and development (R&D) effort in the United States (U.S.) for the production of H_2 using nuclear energy. Tests of solid ceramic membrane electrolyzers have been shown to achieve higher efficiencies than LTE electrolyzers when operated at very high temperatures.

HTGR technology was selected as the reference SMR technology for integration with HTSE technology to produce hydrogen. This selection was based on the same considerations as discussed previously for the oil sands SAGD application, and because iPWR technology does not operate at a sufficiently high temperature to produce the high temperature steam required for the HTSE process.

H_2 production with the HTSE process is most efficient at very high temperatures, with efficiencies greater than 55% achieved for temperatures greater than about 850°C (INL 2010). However, HTGRs that are expected to be commercially deployable before 2030 are expected to only have operating temperatures of about 750°C. Significant research remains to demonstrate performance of materials to be used in Very High Temperature Gas Reactors (VHTGRs) having operating temperatures greater than 850°C, which are not expected to be commercially deployable until after 2030. However, because the HTSE process has been demonstrated to maintain reasonably good efficiency at operating temperatures of 750°C and even lower (efficiencies greater than 40%), this water-splitting process is the technology of choice for further research and development by the United States Department of Energy (DOE). Lower temperature HTGRs in combination with the HTSE water-splitting process is expected to be deployable before 2030.

The electrical generation capacity and additional thermal energy capacity required to support the H_2 production requirement is estimated to be 1000 to 1040 MW_e and 330 to 400 MW_{th}, respectively. It is estimated that about four SC-HTGR modules are needed to provide these electrical and thermal energy requirements. The $LCOH_2$ is estimated to range from C$6.4-6.9/kg$H_2$ (2014). For comparison, a cost estimate for hydrogen production in Canada using an HTGR plant of similar size to the SC-HTGR plant used in this study reports a cost of C$4.3/kgH2 (2014) (El-Emam 2015). The main reason for the difference appears to be due to the assumed capital cost of C$2,100 million for the HTGR plant, which is based on cost information by the International Atomic Energy Agency (IAEA), whereas this study assumes a cost of C$5,585 million, a factor of 2.7 higher. In a separate study by the Idaho National Laboratory (INL), a hydrogen production cost of about C$4.0 (2014) is estimated using essentially the same HTGR plant assumed in this study. In this case, the capital costs assumed for the HTGR and hydrogen plants for the two studies are very similar (C$3.14/kg$H_2$ in this study and C$2.91/kg$H_2$ in the INL study). However, operations and maintenance costs, and variable costs such as fuel, are estimated to be C$1.92/kg$H_2$ in this study and C$1.05 in the INL study. The reason for this difference is unclear. Also, other costs are estimated to be C$1.27/kg$H_2$ in this study, and C$0.18/kg$H_2$ in the INL study. The principal reason for this difference appears to be that the INL study did not include costs for income and property taxes or owner costs.

By comparison, the cost of hydrogen production using natural gas steam methane reforming (StMR) is estimated to be C$2.2-2.3/kg$H_2$ (2014), which accounts for the price of carbon that would be applied to the CO_2 emitted during StMR production of H_2 (assumes carbon or GHG price of C$30/tonne CO_2). Hence, hydrogen production by an integrated HTSE/HTGR system is estimated to be a factor of 3 to 3.5 higher cost than StMR.

<u>Sulfur-Iodine (SI) process</u>. The SI process is a thermochemical water splitting process that uses high temperature heat (750°C – 1000°C) and chemical reactions to produce H_2 and O_2 from water. The efficiency of this process has been demonstrated to be greater than 50% for temperatures greater than 900°C. However, the efficiency drops off quickly with decreasing temperature, dropping below 40% at a temperature of 800°C (INL 2010). Because the SI process requires temperatures greater than 800°C for efficient decomposition of the sulfuric acid, VHTGR type reactors are necessary to integrate/couple with

this process. The Japan HTGR development program is intended to demonstrate HTGRs that operate at temperatures of 850-950°C and are coupled to an SI process for H_2 production. Because HTGRs operating at these temperatures are not expected to be deployable by 2030, the SI water-splitting process was not further evaluated in this study.

Hybrid Sulfur-Iodine (HyS) process. The HyS process is a water splitting processes that combines chemical reactions and electrolysis to produce H_2 and O_2 from water, hence both high temperature heat (750°C – 1000°C) and electricity are required. While not being as actively investigated as other water-splitting processes, it is further considered in this study because of its potential to produce hydrogen at a lower cost than the SI process. However, because this technology does not appear to be under active development, and because of the lack of data on the cost of this technology, the HyS process was not further evaluated in this study.

Other Considerations

In addition to the evaluation of the economics of using SMR technology in the three oil sands applications previously discussed, other potential challenges to the use of SMRs in the oil sands were also evaluated. The results of these evaluations are summarized below.

Human capital and labor expertise requirements for SMRs. No nuclear power plants using any of the SMR technologies evaluated in the Phase I report (PNNL 2016), or further evaluated in this study, have yet been constructed or operated. Hence, as with the overnight EPC cost and LCOE estimates discussed previously, staffing levels developed by the reactor vendors are engineering estimates based on expected performance of these evolutionary SMR technologies. The extensive use of inherent and passive safety features in SMRs is expected to substantially reduce, relative to current generation nuclear power plants, the number of full-time staff needed to safety operate and maintain these SMRs. In fact, some vendors of particularly small SMRs with long-life reactor cores (e.g., StarCore) are claiming that very few full-time staff will be needed at the plant site, and that semi-remote operation may even be possible. These claims remain to be demonstrated.

Of the four reference iPWR and HTGR designs evaluated in this study, staffing levels and skill types are estimated for two of them: NuScale and SC-HTGR. The total full time equivalent (FTE) staffing level for a 12-module NuScale plant (1920 MW_e) and for a single-module SC-HTGR plant (625 MW_{th}) are estimated to be 360 FTEs and 166 FTEs, respectively. A comparison of the number of FTEs by labor category is provided in Figure ES-5. Both estimates assume five-shift, around-the-clock operation of the plant. Also, it is estimated that O&M (including nuclear operators), security, and radiological protection staff compose about 60% of the FTEs for the NuScale plant and almost 75% of the FTEs for the SC-HTGR plant. Many of these staff require specialized training and skills that are unique to nuclear plant operation. Both the number of required staff and the specialized skill/training required by many of these staff may pose a challenge to the oil sands operations due to the remoteness of these facilities. SMR vendors are pursuing means with national regulators to reduce staffing requirements, including putting the reactor underground (enhanced security), automating operations (reduced M&O staffing), refueling the reactor offsite (at the vendor facilities), and demonstrating operational effectiveness through experience with the first deployed units.

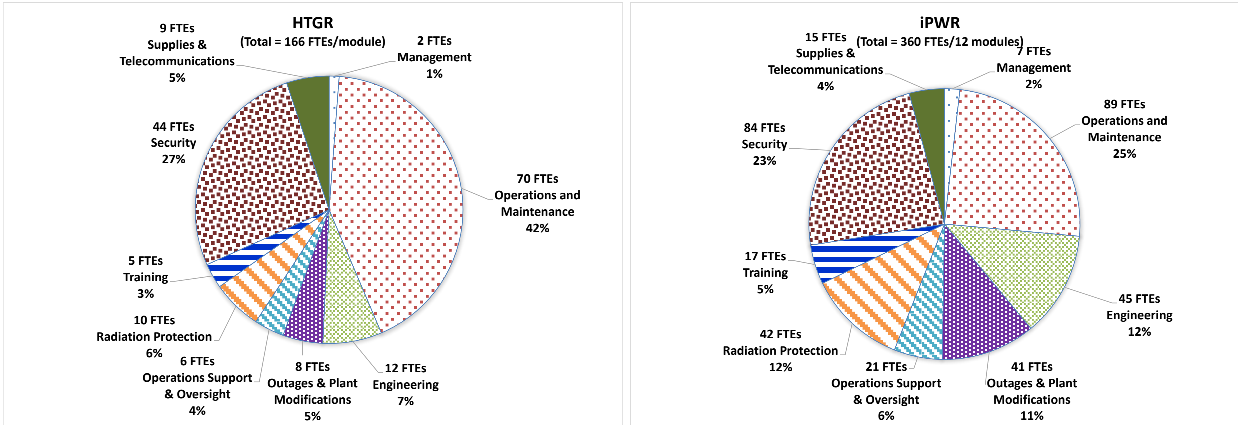

Figure ES-5. Estimated Number of FTEs by Skill Type for HTGR and iPWR

Regulatory approval timelines and expectations. The Canadian Nuclear Safety Commission (CNSC) regulates the use of nuclear energy and nuclear materials in Canada to protect health, safety, security and the environment. The CNSC currently regulates the operation of four nuclear power plants, having 17 operating nuclear power reactors, and several research reactors. While no SMR reactors, as defined in the Phase I report (PNNL 2016), or advanced reactors have been licensed to-date by CNSC, several SMR designs are currently undergoing review, or have applied to be reviewed, under CNSC's pre-licensing Vendor Design Review (VDR) process.

The SMRs and advanced reactors that are being reviewed or have applied to be reviewed within the pre-licensing VDR process are identified in Table 5-1 of this report (including Terrestrial Energy's Integral Molten Salt Reactor [IMSR] design that has completed Phase I of the VDR process). Of the four iPWRs and HTGRs evaluated in this study, just one, the StarCore HTGR, has applied for review under the pre-licensing VDR process. It is important to note that the VDR process is not a license review and so does not result in the issuance of a license by the CNSC. The design and safety of a SMR will still require review by CNSC if the SMR technology is proposed in an application for a CNSC license to construct and operate an SMR. Completing all phases of the VDR process may accelerate the license review process, but it does not replace it.

The licensing process for a SMR in Canada must follow the CNSC licensing process for any new nuclear reactor in Canada (CNSC 2008a). Unlike the CNSC design requirements for large water-cooled nuclear reactors, the CNSC requirements provides for the use of a graded approach to the design of small reactor facilities. The graded approach is a risk-informed method in which the stringency of the design measures and analyses applied is commensurate with the level of risk posed by the reactor facility (i.e., using alternative approaches to meeting design and safety requirements). Nevertheless, designs using the graded approach are still required to demonstrate that they meet the safety objectives and the requirements set out in CNSC regulatory documents. The CNSC estimates that the total time from the receipt of an application to the issuance of a license to operate is approximately nine years, taking into consideration that a number of activities may proceed in parallel. The CNSC also estimates that this total time could potentially be reduced to approximately six to seven years for a very small SMR. The StarCore HTGR may fall into this category.

The CNSC timeline assumes about five year from submission of a new SMR project to CNSC to receiving a construction license from CNSC and a construction time period of about four years. It is reasonable to expect that after the first SMR application, CNSC review and approval of subsequent applications using the same SMR technology would require less time. For example, SMR vendors are claiming construction time periods of two to three years after experience is gained on the first plants, which could potentially reduce the timeline by one to two years. In addition, issuance of a construction license could be reduced by a year or more because of reduced time needed by CNSC to review the design if the design has already been previously reviewed/approved by CNSC (while the fundamental SMR design may be unchanged, some design changes will always be required to account for differences in the characteristics of a new proposed site). These potential reductions in the timeline may also be possible with the first SMR project in Canada depending on the extent to which the SMR construction experience and regulator reviews/approvals in other countries are acceptable to CNSC.

Finally, while the SMART and NuScale iPWR designs have not been submitted to the CNSC for review and licensing, each has been reviewed or is currently being reviewed by the national nuclear regulatory of the home countries of the reactor vendors. Specifically, the SMART reactor design has been reviewed and approved by the South Korean nuclear regulator and the NuScale reactor design is currently being reviewed by the U.S. NRC. Also, while not evaluated in this report, the CAREM-25 iPWR demonstration reactor is currently under construction in Argentina, with expected operation in 2018, and the HTR-PM demonstration HTGR SMR is currently under construction in China, also with expected operation in 2018. While the design reviews by these other national regulators are not a substitute for meeting CNSC requirements, CNSC has indicated that crediting design reviews by other national regulators can potentially facilitate their review (CNSC 2011c).

<u>Potential logistical limitations with shipping SMR components to the Alberta oil fields</u>. One of the potential challenges of deploying nuclear reactors in the Alberta oil sands is the remoteness of the oil extraction and processing facilities and the associated lack of infrastructure for transporting SMR oversize and/or overweight components to the oil sands. For example, the integral reactor pressure vessel modules for three of the reference SMRs evaluated in this report weighs between 303 tonnes and 825 tonnes. Load-bearing restrictions or other (e.g., dimensional) limitations may preclude shipment of large components such as these on specific routes. In fact, based on the results of a previous study that considered this issue, the horizontal clearance limitation on available rail routes to the oil sands currently precludes rail shipments of the large integral reactor pressure vessel modules for three of the four SMRs evaluated in this study.

However, based on the results of a literature search in this study, truck shipments of large components such as these is not only feasible but has been demonstrated in a number of instances. Specifically, there have been numerous truck shipments of components having weights up to 500 tonnes, including shipments to various oil refineries and facilities in the western U.S. and Canada. Also, while never completed, one shipping company had planned on making three shipments of equipment through Idaho and Montana in 2014 that was eventually cancelled due to public opposition. Each of these shipments were planned to be 726 tonnes, width of 8.2 m, and height of 4.9 m. It is noted that these types of shipments do require careful route planning and good communication with local authorities to avoid or minimize shipping delays.

Management of Used Nuclear Fuel and Radioactive Waste. There are two general categories of nuclear waste generated by nuclear power reactors: 1) used nuclear fuel waste and 2) intermediate- and low-level radioactive waste (I/LLRW). Used nuclear fuel is only produced by nuclear reactors and is the residual nuclear fuel that is removed from the reactor after it is no longer effective at producing energy. I/LLRW is any non-fuel radioactive waste and can be produced by any user/producer of nuclear materials, such as hospitals, research facilities, etc. The management and disposition of each are treated differently in Canada.

As with any nuclear power plant, all SMRs generate used nuclear fuel that is highly radioactive. The amount of used fuel generated each year depends on a number of factors, including the type of reactor (e.g., iPWR, HTGR), the size of the reactor in terms of power output, the type of fuel used, and the time period between refuelings. For the iPWRs evaluated in this study, the average amount of used fuel generated each year for a single module is estimated to be between one and three tonnes (0.5 to one m^3). A single module SC-HTGR is expected to annually generate used fuel having somewhat less mass but higher volume on average than iPWRs.

Canada does not yet have a final disposition path for used nuclear fuel. Hence, used nuclear fuel is currently kept in onsite interim storage facilities at each nuclear power plant site. The Nuclear Waste Management Organization of Canada (NWMO), which is funded by generators of used nuclear fuel in Canada, is responsible for designing and implementing a plan for the safe, long-term management of all used nuclear fuel generated in Canada. Since 2010, NWMO has been engaged in a multi-year, community-driven process to identify a site that is willing to host the deep geologic repository. Several potential sites are currently being studied. The current schedule is for operation of a deep geologic repository to begin in the 2040-2045 time frame (NWMO 2017c). While this is a Canadian national facility for the disposal of used nuclear fuel, it is currently only being funded by the current major owners of used nuclear fuel in Canada. Therefore this facility may or may not be available for the disposal of used nuclear fuel generated from SMRs deployed in the Alberta oil sands applications. If not available, then a separate deep geologic repository may need to be developed in Alberta for used nuclear fuel from SMRs deployed in Alberta.

SMRs, like nuclear power plants generally, also generate radioactive waste during plant operations and during final decommissioning. This waste is substantially less radioactive than used nuclear fuel. The amount of radioactive waste generated each year depends on a number of factors, including the type of reactor (e.g., iPWR, HTGR), the number of systems/equipment that are contaminated during plant operations, and the type of fuel used. The amount of I/LLRW generated annually from the operation of the SMR concepts evaluated in this study is not clear since none have yet been built. However, the amount of I/LLW generated from the operation of the large PWR's in the U.S. is generally between 100 and 500 m^3/year per reactor unit (USNRC 2006). Because iPWRs have less operating equipment and a smaller operating staff, the annual volumes of I/LLW is expected to be somewhat less. For HTGRs, the volume is expected to be substantially less because of the use of helium as the coolant rather than water.

Because I/LLW can remain hazardous for 100-500 years, it must be managed in a safe and environmentally responsible manner during this time period. According to Government of Canada's Radioactive Waste Policy Framework (NRC 2015), the owners/operators of nuclear reactor facilities are responsible for “funding, organization, management and operations” of I/LLW storage and disposal facilities, and any other facilities required for the management of this waste.

There are currently no disposal facilities in Canada for I/LLW generated from the operation and decommissioning of nuclear reactor facilities. Hence, I/LLW is currently kept in onsite interim storage facilities at each nuclear power plant site. However, I/LLW disposal facilities are under active development. For example, Ontario Power Generation (OPG) is developing a disposal facility for I/LLW generated by OPG owned and operated nuclear generating stations in Ontario (OPG 2017). Operation of this disposal facility is expected in the mid-2020s. Another example is the development of a I/LLW disposal facility at the Chalk River Laboratory site for the disposal of I/LLW generated predominantly at Canadian Nuclear Laboratories (CNL)-managed sites (CNL 2017). Operation of this facility is scheduled to begin by 2020.

Since I/LLW generators are responsible for “funding, organization, management and operations” of I/LLW storage and disposal facilities, it seems unlikely that I/LLW generated from SMRs deployed in the Alberta oil sands applications would be acceptable for disposal at these other facilities that are currently under development. It may be necessary to develop a disposal facility located in Alberta for I/LLW generated by SMRs deployed in the oil fields applications.

<u>Nuclear Supply Chain</u>. Due to the high upfront cost of developing and maintaining nuclear-grade quality assurance programs, and the lack of new nuclear build projects in North America and Europe over the last 30 years, the nuclear supply chain in these regions has diminished appreciably during this time period. However, because of the large numbers of operating LWRs in North America and Europe, and the large LWR new build projects (mostly PWR plants) in other regions of the world (e.g., China, Russia, India, and the Middle East), the lack of an available supply chain is not considered a significant issue for building iPWR plants. However, challenges do exist including: 1) globalization of the supply chain has complicated processes for ensuring that CNSC quality assurance requirements are met, 2) a domestic construction labor force that is qualified for nuclear plant construction may need to be developed to support timely construction of SMR plants, and 3) specialized iPWR components (e.g., the NuScale Power Module™ and helical coil steam generators) will require development of a supply chain before these SMRs can be deployed.

A larger supply chain issue exists for SMRs utilizing HTGR technology. Industrial-scale HTGRs have not been built or operated in almost 30 years. Hence, specialized components unique to HTGRs are unlikely to be readily available from the existing nuclear supply chain and to require supply chain development to support deployment of HTGR SMRs. Examples of supply chain challenges include (AREVA 2017): 1) commercial scale manufacturing capability for TRISO fuel, which is significantly different than LWR fuel, 2) production of high assay low enriched uranium (i.e., uranium enriched to up to 20% Uranium-235), which is higher enrichment than used in LWR fuel, 3) availability of nuclear-grade graphite, and 4) fabrication of helium turbomachinery (i.e., turbine/compressor). It is noted that China will complete construction and startup of two HTR-PM pebble-bed HTGRs in Spring 2018 (each 250 MW_{th}/105 MW_e). In support of the operation of these demonstration HTGR SMRs, China has developed indigenous TRISO fuel fabrication capability on a scale sufficient to support continuous on-line refueling operations.

Conclusions

Important conclusions from this study are as follows:

I. SMR technologies are capable of providing the electricity, process steam, high temperature steam, and hydrogen requirements of the reference oil sands facilities evaluated in this study.

a. iPWRs are especially well suited to produce the electricity and medium/low pressure process steam requirements for the oil sands mining and extraction facility application.

b. HTGRs are especially well suited to produce the high temperature steam requirements for the oil sands SAGD facility application. While not specifically evaluated, HTGRs can also produce the required electricity, which is a small demand relative to the demand for high temperature steam.

c. HTGRs are especially well suited to meet the hydrogen requirements for the oil sands bitumen upgrading facility application.

II. SMR technologies are expected to be available and deployable in a time frame to play an important role in meeting the overall oil sands emission limit of 100 megatonnes.

a. iPWRs are based on existing PWR technology, including nuclear fuel technology, which has thousands of reactor years of operating experience around the world. In essence, most of the accident safety basis and technology is available today. Furthermore, several iPWR designs have completed or are currently undergoing review by the national nuclear regulator (e.g., the NuScale iPWR is currently undergoing design certification review by the U.S. NRC). As a result, iPWR technology is expected to be deployable well before 2030.

b. HTGRs technologies capable of producing high temperature steam are based on actual but limited operational experience. Most of the current HTGR designs are utilizing fuel technology that is demonstrated to be "intrinsically" safe. Qualification testing of the nuclear fuel to meet strict nuclear regulator requirements is actively progressing in multiple countries (e.g., China, U.S., Japan). Also, two demonstration HTGRs (250 MW_{th} each) are expected to start operation in China by Spring 2018 and StarCore has applied to CNSC for vendor design review status. As a result, HTGR technology is expected to be deployable before 2030.

c. HTGRs in combination with the HTSE water-splitting process is expected to be deployable before 2030. Hydrogen production is most efficient at very high temperatures (greater than about 850°C). HTGRs that are expected to be commercially deployable before 2030 have operating temperatures of about 750°C. Very High Temperature Gas Reactors (VHTGRs) are not expected to be commercially deployable before 2030. However, the HTSE process has been demonstrated to maintain good efficiency at operating temperatures of 750°C and even lower.

d. The iPWR and HTGR technologies were selected based on their TRL and commercial deployability by 2030, and on their capability to provide the electricity, steam, and hydrogen requirements for the Alberta oil fields applications. However, other advanced SMR technologies are currently under active development throughout the world that are potentially applicable to the oil sands applications, but which were judged to not be commercially deployable by 2030. These technologies include sodium fast reactors, molten salt reactors, gas-cooled fast reactors, and heavy liquid metal-cooled fast reactors, of which selected reactor concepts for each were evaluated in the Phase I report (PNNL 2016). Should expansion of oil production from the Alberta oil fields continue after 2030, or more restrictive limits be placed on GHG emissions from the Alberta oil fields after 2030, reconsideration of these technologies at an appropriate time would be prudent.

III. SMR technologies are not currently cost competitive with natural gas cogeneration of electricity and process steam for the surface mining facility application, with natural gas-fired OTSG for production of high temperature steam for the SAGD application, or with StMR production of hydrogen production for the bitumen upgrading application, even after crediting a carbon price of C$30/tonne CO_2 (at the natural gas price of C$3.25/GJ assumed in this study for the surface mining facility and SAGD applications, and C$5.0/GJ assumed for the hydrogen production for bitumen upgrading application).

a. The LCOE for the NuScale iPWR plant is estimated to range from C$125-136/MW-hr (2014), or C$24.7-26.8/tonne steam, which depends on the iPWR technology and number of modules per plant. Estimates of the LCOE for natural gas cogeneration in the oil fields applications range from about C$80/MW-hr (2014) to C$95/MW-hr (2014), which accounts for the price of carbon emissions. On this basis, the cost of iPWR technology is estimated to be higher than natural gas cogeneration by up to C$30-60/MW-hr (2014). Assuming no reductions or improvements in the cost of iPWRs, it is estimated that the price of natural gas would have to increase to C$7.5-8.0/GJ for iPWRs to become economically competitive with natural gas cogeneration. Unlike with natural gas cogeneration, where the largest cost component is the natural gas fuel, the largest cost components of the LCOE for a nuclear power plant project is the cost of financing construction of the plant and income/property taxes. For this analysis, assumptions on financing costs (31%) and income/property taxes (16%) contribute almost 50% to the total LCOE. Further assessment of the appropriateness of these costs for the oil sands surface facility application is recommended.

b. The LCOE for the SC-HTGR plant is estimated to range from C$110-180/MW-hr (2014), with a best estimate of C$140/MWe (C$30-50/tonne steam, with a best estimate of C$37/tonne steam). Estimates of the LCOE for natural gas cogeneration in the oil fields applications range from about C$80/MW-hr (2014) to C$95/MW-hr (2014), which accounts for the price of carbon emissions. On this basis, the cost of HTGR technology is estimated to be higher than natural gas cogeneration by up to C$15-100/MW-hr (2014), with a best estimate of C$50/MW-hr. Assuming no reductions or improvements in the cost of HTGRs, it is estimated that the price of natural gas would have to increase to C$10.5-11.0/GJ for HTGRs to become economically competitive with natural gas-fired OTSGs. Similar to the LCOE for the NuScale iPWR above, financing costs and income/property taxes contribute about 50% of the total LCOE. The same recommendation to assess the appropriateness of the assumptions used to develop the cost estimates for these cost accounts for the oil sands SAGD application is recommended.

c. The $LCOH_2$ for the SC-HTGR/HTSE integrated plant is estimated to range from C$6.4-6.9/$kgH_2$ (2014). The cost of hydrogen production using natural gas StMR is estimated to range from

C$2.2/kg$H_2$ (2014) to C$2.3/kg$H_2$ (2014) after accounting for the price of carbon emissions. On this basis, the cost of SC-HTGR/HTSE technology is estimated to be higher than natural gas cogeneration by a factor of up to 3 to 3.5.

d. The uncertainty in the SMR cost estimates reported in this study are large, predominantly because SMRs have not yet been deployed on an industrial scale. Furthermore, the cost estimates reflected in this study are generally based on cost estimates developed for SMRs producing baseload electricity supplied to the national power grid, further increasing the uncertainty in the cost estimates reported for the Alberta oil fields applications. In addition, the Alberta oil fields are generally located in remote northern locations of Canada, with its associated frigid winter weather conditions. These geographical and weather factors have not been evaluated or incorporated into the SMR cost estimates reported in this study. While the impact of these factors on SMR costs is not known, they would be expected to increase both the capital and operating costs of SMRs reported in this study.

e. Since neither iPWRs or HTGR SMRs have yet been deployed on an industrial scale, resulting in the associated cost estimates having significant uncertainty, it is recommended that the development and deployment of these technologies throughout the world be monitored. Actual deployment implies potential economic competitiveness with competing technologies and improved understanding of the cost of SMR technologies. Specific SMR technologies that show promise of being commercially deployed by 2030 include:

  - iPWRs: 1) construction of the first ACP-100 in China is scheduled to begin in 2018, 2) construction of the first CAREM-25 in Argentina is expected be completed in 2018, 3) the NuScale design is currently being reviewed by the U.S. NRC and operation of the first unit is anticipated for 2026, and 4) the SMART design has been reviewed and approved by the South Korean nuclear regulator and is actively being marketed.

  - HTGRs: 1) construction of the two-unit HTR-PM in China is expected to be completed in 2018, 2) conceptual design of the HTR50S in Japan, which is based on the HTTR test reactor, has been initiated, 3) StarCore of Canada has submitted an application to the CNSC for pre-licensing design review, 4) the SC-HTGR was selected by the Next Generation Nuclear Plant (NGNP) industry alliance for near-term commercialization, and 5) the conceptual design of the Xe-100 in the U.S. has been initiated.

IV. The estimated FTE staffing levels to operate and maintain SMRs having sufficient capacity to support the Alberta oil fields applications is estimated to be between 166 and 360 FTEs. Many of these staff require specialized training and skills that are unique to nuclear plant operation. Both the number of required staff and the specialized skill/training required by many of these staff may pose a challenge to the oil sands operations due to the remoteness of these facilities. SMR vendors are pursuing means to reduce staffing requirements, including putting the reactor underground, automating operations, refueling the reactor offsite, and demonstrating operational effectiveness through experience.

V. The use of a graded approach for licensing of SMRs by CNSC, and the VDR process being made available to reactor vendors by CNSC, holds promise of reducing the approximately 9 year licensing process for large water-cooled reactors to 6-7 years for SMRs. These review and approval timelines can potentially be reduced by 2-3 years if SMR construction time periods of two to three years are achievable (compared to over 4 years assumed in the CNSC timeline) and if issuance of a construction license by CNSC can be reduced by a year or more because the SMR design has either been previously reviewed by the CNSC or regulator design reviews/approvals in other countries are acceptable to CNSC.

VI. Truck shipments of very large (up to 7.9m height, up 8.8 m width, up to122 m long) and heavy (up to 500 tonnes) components to remote locations, generally oil refineries, in the Western U.S. and in Alberta, Canada from northwestern ports in the U.S. have been successfully demonstrated, holding promise for similar shipments of large/heavy reactor components to the Alberta oil sands. However, these types of shipments generally have some public opposition, especially if the transport route is through sensitive wilderness areas. These types of shipments therefore do require careful route planning and good communication with local authorities to avoid or minimize shipping delays.

VII. The current schedule for the start of operation of a deep geologic repository for used nuclear fuel is in the 2040-2045 time frame. However, while this is a Canadian national facility for the disposal of used nuclear fuel, it is currently only being funded by the current major owners of used nuclear fuel in Canada. Therefore, this facility may or may not be available for the disposal of used nuclear fuel generated from SMRs deployed in the Alberta oil sands applications. If not available, then a separate deep geologic repository may need to be developed in Alberta for used nuclear fuel from SMRs deployed in Alberta. Also, since I/LLW generators are responsible for "funding, organization, management and operations" of I/LLW storage and disposal facilities, it seems unlikely that I/LLW generated from SMRs deployed in the Alberta oil sands applications would be acceptable for disposal at other facilities that are currently under development in Canada. It may be necessary to develop a disposal facility located in Alberta for I/LLW generated by SMRs deployed in the oil fields applications.

VIII. The lack of an available supply chain is not considered a significant issue for building iPWR plants. However, challenges do exist including: 1) globalization of the supply chain has complicated processes for ensuring that CNSC quality assurance requirements are met, 2) a domestic construction labor force that is qualified for nuclear plant construction may need to be developed to support timely construction of SMR plants, and 3) specialized iPWR components (e.g., the NuScale Power Module™ and helical coil steam generators) will require development of a supply chain before these SMRs can be deployed. However, a larger supply chain issue exists for SMRs utilizing HTGR technology. Examples of supply chain challenges include (AREVA 2017): 1) commercial scale manufacturing capability for TRISO fuel, which is significantly different than LWR fuel, 2) production of high assay low enriched uranium (i.e., uranium enriched to up to 20% Uranium-235), which is higher enrichment than used in LWR fuel, 3) availability of nuclear-grade graphite, and 4) fabrication of helium turbomachinery (i.e., turbine/compressor).

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Acronyms and Abbreviations

AHWR	advanced heavy water reactor
AC	alternating current
AI	Alberta Innovates
Bi	bismuth
bbl/d	barrels per day
BWR	boiling water reactor
CANDU	CANadian Deuterium Uranium
CNL	Canadian Nuclear Laboratories
CNSC	Canadian Nuclear Safety Commission
CO_2	carbon dioxide
CRDM	control rod drive mechanism
CSS	cyclic steam stimulation
DC	direct current
DOE	U.S. Department of Energy
D_2O	deuterium oxide
EA	environmental assessment
FOAK	first-of-a-kind
FTE	full time equivalent staff
GFR	gas-cooled fast reactor
GHG	greenhouse gases
GJ	gigajoule
H_2	hydrogen
H_2SO_4	sulfuric acid
HEU	high-enriched uranium
HI	hydrogen iodide
HLMC	heavy liquid metal-cooled fast reactor
hr	hour
HTGR	high-temperature gas-cooled reactor
HTSE	high temperature steam electrolysis
HWR	heavy-water reactor
HyS	hybrid sulfur-iodine
I_2	iodine
IAEA	International Atomic Energy Agency
IHX	intermediate heat exchanger
INL	Idaho National Laboratory
iPWR	integral pressurized-water reactor

I/LLRW	intermediate- and low-level radioactive waste
JAEA	Japan Atomic Energy Agency
kSm^3/hr	thousand standard cubic meters per hour
KW	kilowatt
LBE	lead-bismuth eutectic
LCOE	levelized cost of energy
$LCOH_2$	levelized cost of hydrogen
LCOS	levelized cost of steam
LEU	low enriched uranium
LTE	low temperature electrolysis
LWR	light-water reactor
m	meter
MPa	megapascal
MPaG	MPa (gauge)
MSR	molten salt reactor
MW	megawatt
MW_e	megawatt electric
MWhr	megawatt-hour
MW_{th}	megawatt thermal
NEI	Nuclear Energy Institute
NFT	Naphthenic Froth Treatment
NGNP	Next Generation Nuclear Plant
NHSS	nuclear heat supply system
NOAK	n^{th}-of-a-kind
NPP	nuclear power plant
NRC	Natural Resources Canada
NWMO	Nuclear Waste Management Organization of Canada
O_2	oxygen
OPG	Ontario Power Generation
OTSG	once through steam generator
Pb	lead
PCS	primary cooling system
PEM	proton exchange membrane
PFT	Paraffinic Froth Treatment
PHTS	primary heat transport system
PHWR	pressurized heavy water reactor
PNNL	Pacific Northwest National Laboratory
PTAC	Petroleum Technology Alliance Canada

PWR	pressurized-water reactor
R&D	research and development
RCS	reactor coolant system
RPV	reactor pressure vessel
SAGD	Steam-Assisted Gravity Drainage
SCO	synthetic crude oil
SFR	sodium fast reactor
SI	sulfur-iodine
SMR	Small Modular Nuclear Reactor
StMR	Steam Methane Reforming
SO_2	sulfur dioxide
SOEC	solid oxide electrolysis cell
SOW	statement of work
TRISO	tristructural-isotropic
TRL	technology readiness level
UO_2	uranium dioxide
USNRC	U.S. Nuclear Regulatory Commission
VDR	Vendor Design Review
yr	year

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1.0 Introduction

1.1 Background

On November 22, 2015 the Government of Alberta announced its Climate Change Leadership Plan, which included the following statements with respect to oil sands emissions:

- *"The government will legislate an overall oil sands emissions limit. We will grow our economy by applying technology to reduce our carbon output per barrel, which is what this limit will promote.*
- *An overall oil sands emission limit of 100 megatonnes will be set, with provisions for new upgrading and co-generation.*

In addition, it was announced that a price on carbon would be phased in over time to provide an incentive to reduce greenhouse gas pollution that causes climate change. At present, the power and steam requirements of the heavy oil industry are predominantly met by natural gas. Small Modular Nuclear Reactors (SMRs) could potentially play a role in providing competitively-priced, environmentally-acceptable, and dependable/reliable heat and power for the oil sands and electricity sectors, in order to meet the above-stated aspects of the Climate Change Leadership Plan.

SMRs have the following potential advantages relative to current generation power sources, including, in some cases, large nuclear power plants (NPPs):

- Near zero emissions of greenhouse gases (GHGs) and other potentially deleterious substances during operation;
- Passive and inherent safety features compared to existing NPPs that substantially reduce the risk of severe accidents;[5]
- Economics and quality afforded by factory production of plant components compared to the on-site fabrication and construction used at existing NPPs (which offsets the economies-of-scale generally associated with larger capacity reactors); and
- More flexibility relative to large nuclear power plants in terms of financing (lower initial capital investment and therefore lower risk), scalability (incremental capacity additions are smaller and more adaptable to changing power requirements and needs), and plant siting (can be installed at

[5] Passive safety features are plant components that will act to safely shutdown the nuclear reactor during an off-normal operational-upset event without the use of operator actions or the use of actively-operated systems. An example is the use of natural circulation of reactor coolant to passively remove decay heat in the reactor core in the event there is a loss of electric power to the plant that prevents the use of pumps, motor-operated valves, etc., that would generally be used during normal plant operation to provide forced circulation of coolant to remove the reactor decay heat. In contrast, inherent safety features refer to the natural nuclear response characteristics of the fuel/coolant that act to slowdown the nuclear chain reaction when a certain characteristic of the material changes. For example, all reactors licensed by the NRC in the U.S. must have a negative fuel temperature coefficient of reactivity meaning that as the temperature of the fuel increases (such as due to a loss of decay heat removal capability), the reactivity or power level of the reactor will decrease and return the reactor to its original state.

locations unable to accommodate traditional larger reactors because reactor/plant components are smaller and more transportable to remote locations).

Potential disadvantages of SMRs relative to current generation power sources, including, in some cases, large nuclear power plants:

- Lack of economies-of-scale for both construction and operating costs that are available with larger nuclear power plants (although the simpler designs of SMRs may be able to offset this disadvantage to some extent);

- Lack of an available supply chain for specialized reactor components and for nuclear fuel types that are significantly different from the light-water reactor fuel currently used predominantly around the world;

- As with nuclear power plants generally, SMRs generate used nuclear fuel that remains radioactive for thousands of years thereby requiring specialized treatment and disposition; and

- As with nuclear power plants generally, SMRs generate radiation and radioactive materials that can be inadvertently released into the environment either during normal operations or as the result of a severe accident (although, as discussed above, the risk of severe accidents is substantially reduced in most SMRs designs).

SMR technology may have great potential significance to Alberta, especially if SMRs can be demonstrated to be viable under Alberta conditions and applicable to the Province's oil sands industry. This industry needs to know about major developments that may affect their business and choice of energy sources. An understanding of the commercial potential of SMRs is therefore very relevant to this industry.

With this background, Alberta Innovates (AI) contracted with PNNL to evaluate advances in SMR technology and their potential for application in Alberta for reducing GHG emissions through multi-purpose steam, electricity, and/or heat generation. The assessment is being completed in phases. The Phase I assessment was completed in November 2016, and is documented in Report PNNL-25978, "Deployability of Small Modular Nuclear Reactors for Alberta Applications" (PNNL 2016). The results of Phase II of this study are documented in this report.

The intent of both the Phase I report and this Phase II report is to provide intelligence to AI regarding the potential for SMR applications in the Alberta oil sands sector, using publicly-available information. Neither the commissioning of this study, or the release of this report, imply that the authors, PNNL, AI, or its collaborators advocate the development or deployment of SMRs.

1.2 Summary of Phase I Study

The objective of the Phase I study was to provide a high-level assessment of the current state of development, and potential for further development, of SMRs and their prospective application in Alberta for multi-purpose process steam/electricity/district heat generation for Alberta's oil sands in-situ oil recovery or Steam-Assisted Gravity Drainage (SAGD) operations to fulfill future growth and to reduce GHG emissions. Dozens of SMR designs were reviewed and included in the Phase I assessment if they were judged to be under active development for deployment as SMRs and to be deployable by about the 2030 time frame. Twenty-six reactor designs were included in the assessment representing the following general reactor types: (1) integral pressurized water reactors (iPWRs), (2) heavy-water cooled and moderated reactors (HWRs), (3) high-temperature gas-cooled reactors (HGTRs), (4) molten salt reactors (MSRs), (5) sodium fast reactors (SFRs), (6) gas-cooled fast reactors (GFRs), and (7) heavy liquid metal-cooled (HLMC) fast reactors. A summary of some of the design and operational features of each of the 26 reactor designs evaluated in the Phase I study is provided in Appendix A. This appendix also briefly summarizes promising new SMR concepts (i.e., TerraPower traveling wave reactor) that have emerged since that study.

The Phase I study also briefly considered SMRs used in marine/naval vessels. While there is significant operational history with these types of SMRs, important design features generally make them impractical for use as commercial, land-based SMRs. For example, a common design feature of marine/naval vessels is the use of high-enriched uranium (HEU)[6] fuel that is not available for commercial applications. SMR designs based on marine/naval SMR designs are not generally being pursued by reactor vendors for commercial applications. The Phase I study did, however, identify Russian SMR design concepts that are based on their marine/naval reactor designs (e.g., RITM-200, SVBR-100).

Each of the 26 SMR designs was evaluated using Decision Analysis techniques with an end goal to develop an overall ranking of each concept relative to a pre-defined set of criteria. A set of 13 criteria were defined as being relevant to the assessment of SMR designs in Alberta. These criteria primarily related to the capability of the various SMR designs to meet the energy and steam requirements of SAGD facilities and support the achievement of significant GHG reductions in the province by 2030 - as articulated in the Climate Leadership Plan discussed above, and include other performance metrics considered potentially important to various stakeholders. Generally, reactor concepts based on HTGR technology ranked the highest of the reactor types, which is not unexpected since HTGRs operate at temperatures and pressures that readily support the generation of steam having sufficient quality for oil sands SAGD operations.

The reactor design having the highest aggregate score was the StarCore HTGR [Canada]. Also highly ranked was the HTR50S HTGR reactor by the Japan Atomic Energy Agency (JAEA). One other reactor design that ranked high was the 4S SFR by Toshiba [Japan]. As with HTGRs, reactor concepts based on SFR technology score high on generating steam having sufficient quality for oil sands SAGD operation.

1.3 Phase II Study Objectives

The key objectives of this Phase II study are as follows: 1) to provide a techno-economic assessment of SMRs for applications in SAGD, surface mining, and hydrogen production in the oil sands, to displace the incumbent natural gas-based technologies, and thereby reduce GHG emissions associated with steam,

[6] HEU fuel is defined as having a Uranium-235 (U-235) content greater than or equal to 20% while LEU fuel is defined as having a U-235 content less than 20%. None of the SMR concepts evaluated in the Phase I study used HEU fuel.

electricity and hydrogen production, 2) to identify opportunities for cost reductions associated with SMRs that would facilitate increased cost-competitiveness against natural gas, and 3) to contextualize the non-technical deployment challenges of SMRs in Alberta, including regulatory, human capital, used fuel and radioactive waste, supply chain, and logistical hurdles. This study uses the information compiled for each of the 26 SMR concepts identified in the Phase I report to assess and identify the most likely or viable SMR concepts for each of the following three oil sands activities for application in Alberta by 2030:

- Surface mining of bitumen from the Alberta oil sands. This assessment assumes the reference surface mining facility produces 200,000 barrels per day (bbl/d) of bitumen having steam and electricity consumption as follows:

Treatment Method	Medium Pressure Steam (2.1 MPaG, 225ºC)		Low Pressure Steam (1.05 MPaG, 210ºC)		Power Consumption
	Mass (tonnes/hr)	Heat (GJ/hr)	Mass (tonnes/hr)	Heat (GJ/hr)	MW_e
	High Grade Ore to Low Grade Ore				
Paraffinic Froth Treatment	155 – 303	434 – 623	511 – 895	1051 – 1879	127 – 175
Naphathanic Froth Treatment	172 – 247	389 – 537	448 – 642	921 – 1320	127 – 175

- In-situ recovery, or SAGD, of bitumen from the Alberta oil sands. This assessment assumes the reference SAGD facility produces 33,000 bbl/d of bitumen having steam and electricity consumption as follows:

High Pressure Steam (10 MPaG, 310ºC)		Low Pressure Steam (1.05 MPaG, 210ºC)		Power Consumption
Mass (tonnes/hr)	Heat (GJ/hr)	Mass (tonnes/hr)	Heat (GJ/hr)	MW_e
655	1556	15	35	18

- Hydrogen production for upgrading of bitumen extracted from the Alberta oil sands. This assessment assumes the reference upgrader facility produces 200,000 bbl/d and consumes 315,000 cubic meters of hydrogen per hour at normal temperature and pressure conditions (Nm^3/hr).

1.4 Key Intelligence Outcomes and Study Purpose

The purpose of this study is to provide technology intelligence to AI in the area of SMR technologies and their deployability for applications in the oil sands industry. Specifically with regard to each of the oil sands application areas discussed in Section 1.3, a key intelligence outcome is identification of a preferred SMR technology based on factors such as technology readiness level (TRL), refueling requirements, electricity/steam/hydrogen production capacity as applicable, security and safety features, operational flexibility and simplicity, and levelized cost. With regards to cost, areas that hold potential for significant cost reductions with deployment of SMRs was a key intelligence outcome. Other key intelligence outcomes include required staffing levels and associated specialized expertise, regulatory/licensing challenges, logistical challenges with accessibility to the oil sands of large reactor components, the nuclear reactor supply chain, and management and disposition of used fuel and radioactive waste.

1.5 Report Organization

The remainder of this report is organized to include a separate section on each of the oils sands application areas: 1) Section 2, Alberta Oil Sands Surface Mining Application, 2) Section 3, Alberta Oil Sands In-situ Extraction Application, and 3) Section 4, Hydrogen Production for Alberta Oil Sands Bitumen Upgrading Application. Section 5 discusses several challenges with deployment of SMR technology in the Alberta oil sands. A final section, Section 6, provides an overview of the conclusions and recommendations from this Phase II study.

1.6 Glossary of Nuclear Reactor Terms

This report utilizes terminology that, while familiar to those who work in the nuclear industry, may not be familiar to those who primarily work in the oil sands industry. Hence, a glossary of key terms is provided in this section to assist readers unfamiliar with nuclear terminology. References for many of these terms are taken from the Phase I report (PNNL 2016) and from the U.S. Nuclear Regulatory Commission (USNRC) webpage (USNRC 2017).

Boiling-water Reactor (BWR). A common nuclear power reactor design in which water flows upward through the core, where it is heated by fission and allowed to boil in the reactor vessel. The resulting steam then drives turbines, which activate generators to produce electrical power. BWRs operate similarly to electrical plants using fossil fuel (e.g., coal), except that the BWRs are powered by nuclear fuel assemblies in the reactor core.

Containment Building or Containment Structure. An air-tight building or structure, usually made of steel-reinforced concrete, that houses the nuclear reactor, reactor coolant pumps, pressurizer and steam generator (for pressurized water reactors), and other equipment and piping. The purpose of the Containment Building is to contain radiological materials released into the atmosphere as a result of an accident, and thereby prevent or mitigate a release to the public. Generally, a single Reactor Module is contained within a single Containment Building or Containment Structure.

Gas-cooled Fast Reactor (GFR). Like HTGRs, GFRs generally utilize helium as the reactor coolant (although other materials such as carbon dioxide can be used). An important difference with HTGRs is that the neutron moderator, large quantities of nuclear-grade graphite, is not necessary.

Heavy Liquid Metal-cooled (HLMC) fast reactors. HLMC fast reactors utilize one of two possible liquid metals for the reactor coolant: pure lead (Pb) or lead-bismuth (Pb-Bi) eutectic (LBE). The safety features are similar to those of the SFRs.

Heavy-water Moderated Reactor (HWR). A reactor that uses heavy water (D_2O) as its moderator. Heavy water is an excellent moderator and thus permits the use of natural uranium as a fuel. The most common type of HWR in use today is the Canadian-developed CANDU (CANadian Deuterium Uranium) reactor. HWRs are the second most common type of nuclear power reactor utilized throughout the world.

High Temperature Gas-cooled Reactor (HTGR). An inherently safe (i.e., no harmful release of radioactive material is possible under any accident conditions) nuclear reactor technology that generally utilizes helium gas as the coolant, nuclear-grade graphite as the neutron moderator, and enriched uranium in the fuel. There are basically two HTGR design concepts: pebble-bed core and prismatic-block core. Both use tristructural-isotropic (TRISO) fuel that is designed to not crack at very high temperatures. In a pebble-bed reactor, thousands of TRISO fuel particles are dispersed into graphite pebbles. In a prismatic-block reactor, the TRISO fuel particles are fabricated into compacts and placed in a graphite block matrix. Additional information on the TRISO fuel is provided in the Phase I report (PNNL 2016).

Light Water Reactor (LWR). A term used to describe reactors using ordinary water as coolant, including boiling water reactors (BWRs) and pressurized water reactors (PWRs), the most common types used in the United States and throughout the world. LWRs generally use enriched uranium in the fuel.

Molten Salt Reactor (MSR). MSRs use molten fluoride salts for the reactor coolant and graphite as the neutron moderator. The fuel is typically a molten mixture of the lithium and beryllium fluoride salt coolant with low-enriched uranium fluorides dissolved in the mixture, although solid fuel concepts are being developed.

Nuclear Steam Supply System (NSSS). All of the components of a nuclear power plant that are necessary for generating steam that can then be used in either process steam applications or for driving a turbine-generator to produce electricity. Major components of the NSSS include the reactor, reactor coolant pumps, steam generators (for pressurized water reactors), and associated piping for transferring the reactor coolant and steam.

Pressurized-water Reactor (PWR). A common nuclear power reactor design in which very pure water is heated to a very high temperature by fission, kept under high pressure (to prevent it from boiling), and converted to steam by a steam generator (rather than by boiling, as in a BWR). The resulting steam is used to drive turbines, which activate generators to produce electrical power. A PWR essentially operates like a pressure cooker, where a lid is tightly placed over a pot of heated water, causing the pressure inside to increase as the temperature increases (because the steam cannot escape) but keeping the water from boiling at the usual 212°F (100°C).

Reactor Building. A building that prevents or controls (confines) the release of radioactive material to the environment during operation or during accidents. This building differs from the Containment Building in that other systems, such as filtration systems, are used to contain the release rather than an air-tight building.

Reactor Coolant System (RCS). The system used to remove energy from the reactor core and transfer that energy either directly or indirectly to the steam turbine. Major components of the RCS include the reactor, reactor coolant pumps, steam generators (for pressurized water reactors), and associated piping for transferring the reactor coolant.

Reactor Core. The central portion of a nuclear reactor where the nuclear fission reactions occur and which contains the fuel assemblies, coolant/moderator, control rods, and core support structures.

Reactor Module. For SMRs, a reactor module includes many or all of the components of the RCS for a single nuclear reactor. A single nuclear power plant may have one or more reactor modules.

Reactor Pressure Vessel (RPV). A strong-walled stainless steel container housing the reactor core of most types of power reactors.

Sodium Fast Reactor (SFR). The SFR utilizes liquid sodium metal as the reactor core coolant and has a number of advanced safety features relative to LWRs.

Small Modular Nuclear Reactor (SMR). For the purposes of this report, an SMR refers to a nuclear reactor having an equivalent electric power generation design capacity in the range of 20 – 300 megawatt-electric (MWe). The term “modular” in the context of SMRs refers to the fabrication of major components of the NSSS in a factory environment and to deliver and assemble these components at a site in modules.

2.0 Alberta Oil Sands Surface Mining of Bitumen Application

There are two principal methods used to extract bitumen from the Alberta oil sands: 1) surface mining of the oil sands followed by bitumen extraction and froth treatment and 2) in-situ recovery of the bitumen using processes such as steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). With either method, the resultant bitumen product may need to be upgraded to synthetic crude oil (SCO), which has the effect of reducing viscosity and increasing the hydrogen to carbon ratio thus enabling pipeline transportation without the need for diluent addition while increasing market value. This section of the report assesses the potential for using SMRs to provide the steam and electricity requirements for extraction and froth treatment of bitumen from mined oil sands. The potential application of SMRs for in-situ recovery of bitumen and for producing hydrogen for bitumen upgrading are assessed in later sections of this report.

For the purposes of this assessment, the reference oil sands surface mining facility developed by Tetra Tech (Tetra Tech 2017) was utilized. The reference facility is a fictitious stand-alone mine, having a bitumen production capacity of 200,000 barrels per day (bbl/d), that is not integrated with either a bitumen upgrader or with an adjacent in-situ extraction facility. A material and energy flow diagram was developed for the reference facility for each of the following four bitumen froth treatment scenarios:

1) Paraffinic Froth Treatment (PFT) – high grade material,

2) PFT – low grade material,

3) Naphthenic Froth Treatment (NFT) – high grade material, and

4) NFT – low grade material.

The steam and electricity consumption for each of these scenarios is provided in Table 2-1.

Table 2-1. Steam and Electricity Consumption for Reference Mining and Extraction Facility

Bitumen Froth Treatment Method	Bitumen Grade	Medium Pressure Steam (2.1 MPaG, 225ºC) Mass (tonnes/hr)	Medium Pressure Steam (2.1 MPaG, 225ºC) Heat (GJ/hr)	Low Pressure Steam (1.05 MPaG, 210ºC) Mass (tonnes/hr)	Low Pressure Steam (1.05 MPaG, 210ºC) Heat (GJ/hr)	Power Consumption MWe
Paraffinic Froth Treatment	High	155	434	511	1051	127
	Low	303	623	895	1879	175
Naphathanic Froth Treatment	High	172	389	448	921	127
	Low	247	537	642	1320	175

The reference facility is assumed to utilize gas turbine generators (GTGs) to cogenerate the heat and electricity consumed in the facility. Based on a requirement to be capable of producing steam having the minimum characteristics defined in Table 2-1, and considering other criteria, a reference SMR technology was selected and integrated into the reference surface mining facility flowsheet, replacing the GTG cogeneration plant. The economics of the reference SMR were then evaluated and compared to the reference GTG cogeneration technology.

2.1 Selection of the Reference SMR Technology

The criteria defined for selecting the reference SMR technology for the oil sands surface mining facility application are as follows:

- The steam characteristics and steam/electricity production meet the reference facility requirements defined in Table 2-1.
- The technology readiness level (TRL)[7] is sufficiently high (TRL of 6 or greater) as to support implementation in the oil sands well ahead of the year 2030.
- Investment in development and demonstration of the technology by the reactor vendor appears to be sufficient to support commercialization and implementation well before the year 2030.
- Advanced passive/inherent safety features are incorporated into the reactor design, thus minimizing operational complexity and the associated nuclear-qualified operations/maintenance staffing that would need to be located in the harsh northern Alberta climate.

Based on assessment of each of the 26 SMR concepts evaluated in Phase 1 relative to these criteria, which are summarized in Appendix A of this report, iPWR technology was selected as the reference SMR technology for the oil sands mining and extraction facility application. This selection was based on the following considerations:

- iPWRs are capable of producing the electricity and process steam requirements defined in the reference flowsheets for both Naphthenic and Paraffinic Froth Treatment, as defined in Table 2-1. iPWRs are generally being designed to produce superheated steam (Indirect Rankine Cycle) having characteristics of 2.3 – 5.8 MPa and 290 – 320°C. Standard available technologies such as steam heaters or pressure reducing (or letdown) valves and associated systems can readily be incorporated into the design to use the superheated steam to produce saturated steam at the conditions defined in Table 2-1. This is discussed further in Section 2.3 below.
- iPWR technology is based on PWR technology that is utilized extensively for electricity production, which has over 50 years of operating experience representing thousands of reactor

[7] Alberta Innovates standard definition/classification for TRL: (1) TRL 1, Basic principles observed and reported, (2) TRL 2, Technology concept and/or application formulated, (3) TRL 3, Analytical and experimental critical function and/or characteristic proof-of-concept, (4) TRL 4, Component/subsystem validation in laboratory environment, (5) TRL 5, Component validation in relevant environment, (6) TRL 6, System/subsystem model or prototyping demonstration in a simulated end-to-end environment; typically 0.1 to 5% of full scale, (7) TRL 7, System prototyping demonstration in an operational environment; typically Pilot Plant at 5% of Full Scale, (8) TRL 8, Actual system completed and qualified through test and demonstration in an operational environment; demonstration at typically 25% of commercial scale, (9) TRL 9, Actual system proven through successful deployment in an operational setting; commercial operation, and (10) TRL 10, Widespread Adoption.

years of operation. PWR technology is utilized in 64% of all nuclear power plants in operation throughout the world as of the year 2016 (280 of 436 nuclear reactors).

- While iPWR technology is based on PWR technology, the various design concepts range from relatively minor to relatively modest technology evolutions from standard PWR technology, principally reflecting the degree to which evolutionary passive safety features are being incorporated and demonstrated. However, in almost all of the designs, the iPWR technology utilizes the same nuclear fuel technology that is utilized in standard PWRs, which has thousands of reactor years of demonstrated operational performance, and therefore does not require the rigorous qualification testing that other SMR technologies require to demonstrate that it meets regulatory performance requirements.

- For many of the iPWR designs, the vendors are making substantial investments in the technology. Specifically, significant investments are being made in the ACP-100 (China), CAREM-25 (Argentina), NuScale (USA), and SMART (South Korea). Furthermore, the CAREM-25 reactor is currently under construction, the SMART reactor design has been reviewed and approved by the South Korean nuclear regulator, and the NuScale reactor design is currently being reviewed by the U.S. NRC.

- Little information is available on expected staffing levels for iPWRs and SMRs generally. The significant incorporation of passive safety features in iPWRs and corresponding reduction in the need for active safety systems is expected to result in a significant reduction in the full time equivalent (FTE) staffing levels, on a per MWe basis, relative to that required by current generation PWR technology. Based on the lack of staffing information, however, this criteria is not a discriminator for selecting the reference SMR.

It is noted that the PHWR-220, an HWR SMR based on CANDU technology, satisfies many of the above criteria also. However, because of the additional complexity and staffing associated with continuous on-line refueling, and the relatively limited passive safety features for this design, iPWR technology was judged to be preferable for the oil sands surface mining of bitumen facility application.

2.2 Overview of the Reference iPWR

For the purposes of this evaluation, the NuScale SMR and the SMART SMR are used as the reference iPWRs for the oil sands surface mining of bitumen facility application. There are three principal reasons for this: 1) each is one of the four iPWR reactor designs identified in the previous section that are receiving significant investment, 2) the designs are sufficiently advanced such that the SMART iPWR design has been reviewed and approved by the South Korean nuclear regulator and the NuScale iPWR design has been accepted for and is currently undergoing design review by the nuclear regulator in the U.S., and 3) of the iPWR design concepts, the NuScale design has the most comprehensive information available in the open literature, including details on preliminary estimates of its economics and staffing levels. However, the reader is cautioned that these iPWR designs, like all of the iPWR designs, are still in the development phase and so there is no practical experience with the construction and operation of these evolutionary PWR designs. A brief overview of each of the two reference iPWRs is provided below.

NuScale by NuScale Power LLC [USA]

The NuScale reactor has a design electrical/thermal capacity of 45 MW_e/160 MW_{th}. The integral reactor pressure vessel (RPV) contains the reactor core, pressurizer, and steam generators. The RPV and control rod drive mechanisms (CRDMs) are housed within an integral containment vessel, referred to as the NuScale Power Module™ (NPM). The NPM has a height of 25 m, a diameter of 4.6 m, and weighs 303 tonnes. Superheated steam exits the NPM having the following characteristics: pressure – 3.5 MPa, temperature – 300°C, and mass flow – 67 kg/s. Cooling during normal plant operations is by natural circulation and so there are no reactor coolant pumps. The NuScale plant design will allow the deployment of one to twelve modules to attain larger plant output as demands arise. The footprint of a 12 module plant is approximately 14 hectares. Figure 2-1 provides a conceptual drawing of the NuScale reactor module and plant.

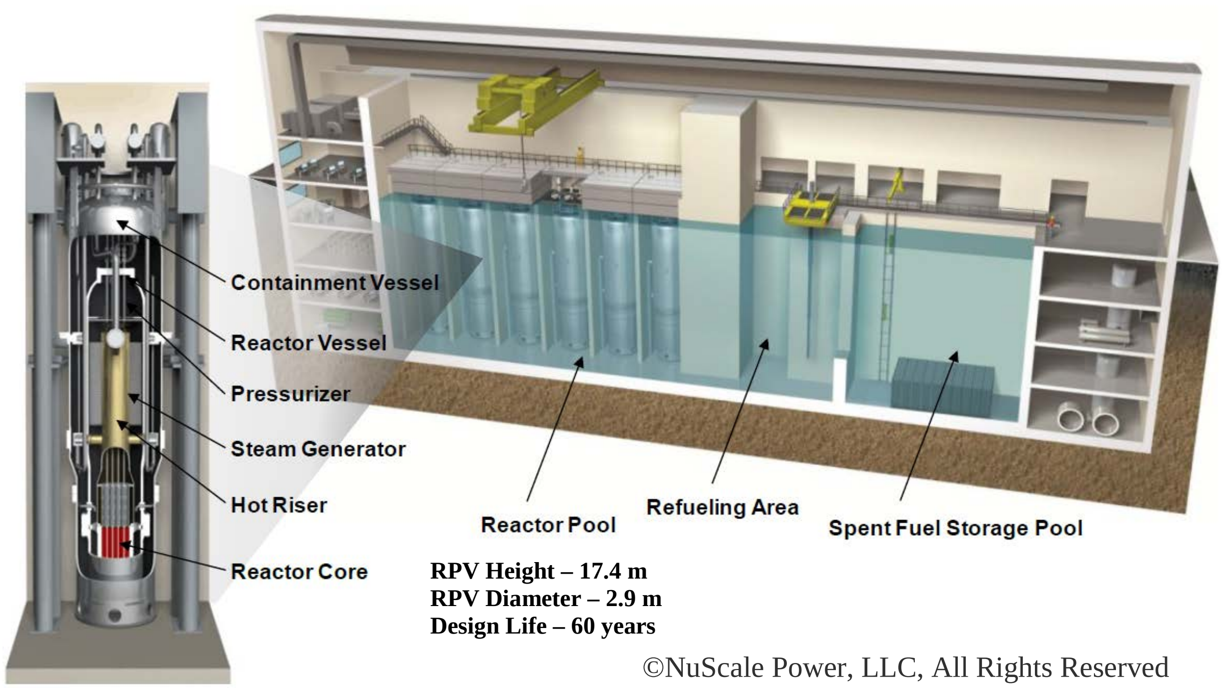

Figure 2-1. Conceptual Drawing of NuScale Power Module® and Plant (NuScale 2016)

The reactor core is cooled by natural circulation of the cooling water during normal plant operation. Passive safety features allow for the passive removal of decay heat for an unlimited time without safety-related emergency alternating current (AC) or direct current (DC) power or additional water or operator actions. The reactor pool (including the integral RPV and containment vessel), spent fuel pool, and main control room are located underground for protection against aircraft impact.

The design certification application to the U.S. NRC was submitted in January 2017. In addition, the U.S. NRC staff previously expended several thousand person-hours on pre-application review of the NuScale design. Much of the required component testing has been completed, although testing is continuing on the CRDMs and fuel assemblies. Construction of the first NuScale plant on the Idaho National Laboratory site in Idaho, U.S. is expected to begin in 2019 and to start operation in 2023.

Additional information about NuScale can be found in the following references: IAEA 2014, NuScale 2015, ANS 2015, Nuclear Energy Insider 2016, NuScale 2016, and ASME 2014.

SMART (System-integrated Modular Advanced ReacTor) by Korea Atomic Energy Research Institute (KAERI) [Republic of Korea]

The SMART reactor is an iPWR having a design electrical/thermal capacity of 100 MW_e/330 MW_{th}. The integral RPV contains the reactor core, pressurizer, steam generators, and reactor coolant pumps. The RPV has a height of 18.5 m, a diameter of 6.5 m, and weighs 750 tonnes. Superheated steam exits the RPV having the following characteristics: pressure – 5.2 MPa, temperature – 298°C, and mass flow – 160.8 kg/s. The CRDMs are located outside the RPV. The RPV and CRDMs are surrounded by a large containment building. Each containment building is designed to contain a single reactor module. The footprint of a two module plant is approximately 12 hectares. Figure 2-2 provides a conceptual drawing of the SMART reactor and plant.

The reactor core is cooled by the forced circulation of the cooling water during normal plant operation. Passive safety features allow for the passive removal of decay heat for 36 hours without safety-related emergency AC power or operator actions. The reactor is located above ground, similar to current-day PWRs.

Standard Design Approval was received from the Korean nuclear regulator on July 4, 2012. The reactor is being actively marketed. Saudi Arabia has expressed interest in hosting the first plant, however no sales have yet been announced. All component and fuel testing necessary to receive the design approval have been completed.

Additional information about SMART can be found in the following references: KAERI 2011a, KAERI 2013, and IAEA 2014.

Relative Merits of the Different Design Approaches

As is clear from the above descriptions, the design approaches taken by the reactor vendors for the two reference iPWRs are vastly different. The most visually-obvious difference is in the approaches taken for providing containment of radioactive materials in the event of an accident. The SMART reactor containment design takes a more traditional approach of placing a single reactor and associated reactor coolant system inside a large containment building, taking advantage of the large design and operational experience of current generation PWRs. Containment buildings are large reinforced, pre-stressed concrete structures that are designed to not only contain releases from postulated accidents but to protect the reactor against aircraft impacts. For the SMART reactor design, the containment building and reactor are above ground.

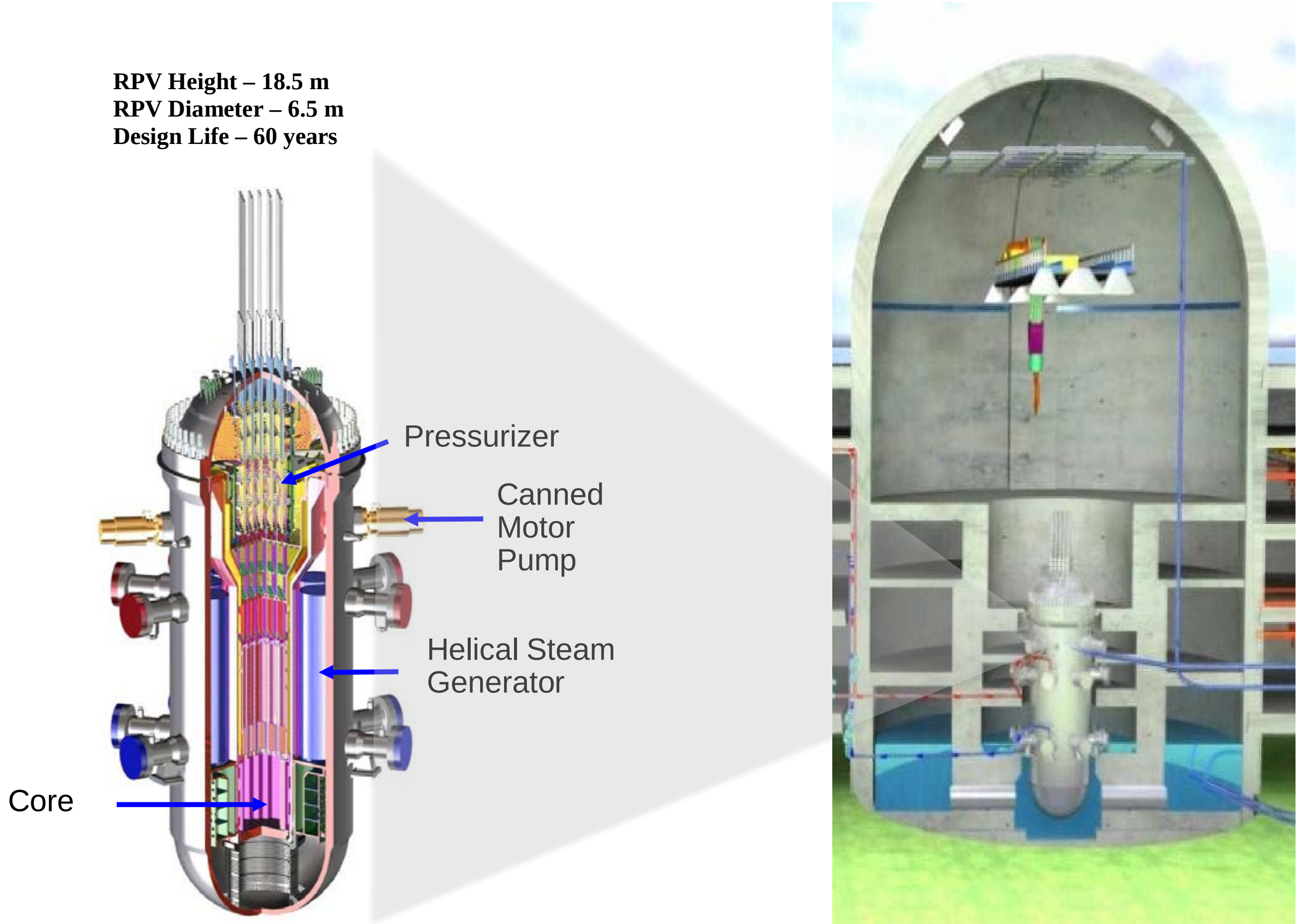

Figure 2-2. Conceptual Drawing of SMART Reactor (KAERI 2013)

The NuScale reactor approach to providing containment is an evolutionary design in which the reactor/RPV and reactor coolant system are contained within a steel containment vessel, with the entire package referred to as the NuScale Power Module™ or NPM. The steel containment vessel is designed to contain releases of radioactive material from postulated accidents. Multiple NPMs are incorporated into a single reactor building and are located below ground level. The reactor building is a steel-lined concrete structure that is designed to confine radioactive releases and provide the structural foundation for the large reactor pool. A significant portion of the reactor building is located below ground level, including the reactor pool and NPMs, while the above grade portion is designed to protect against aircraft impacts.

To provide some context for the differences between the SMART and NuScale approaches to containment design, Figure 2-3 provides a somewhat-to-scale side-by-side comparison of the SMART reactor containment building and the NuScale NPM to a typical PWR containment building.[8] Note that the SMART reactor containment building and the typical PWR containment building are very similar in

[8] The typical PWR reactor building shown is for the Indian Point Unit 2 Westinghouse 4-loop PWR located near New York City, New York, USA. The reactor has a design capacity of 1032 MWe, 3218 MWth.

size, while the NPM is substantially smaller. However, some important perspectives to consider in this comparison are as follows:

- The NPM is a 50 MWe reactor, the SMART is a 100 MWe reactor, and the typical PWR is a 1032 MWe reactor.

- The typical PWR clearly benefits from economies-of-scale from a containment building perspective: the typical PWR produces 10 times the electricity for essentially the same size containment building.

- About 21 NPMs are required to produce the same amount of electricity as the typical PWR. NuScale has estimated that about 126 NPMs could fit within a typical PWR containment building. While dimensions of the NuScale reactor building are not available, it is estimated that the dimensions are approximately 33 m wide by 55m long by 35 m high (based on information in NuScale 2014). This suggests that the land area of the NuScale reactor building is somewhat larger than that of the SMART or typical PWR containment building, while the height of the NuScale reactor building appears to be almost half that of the containment buildings.[9]

- The NuScale reactor is reported to have a thermal-to-electricity conversion efficiency of 28-30%, somewhat less than the 32-35% reported for the SMART reactor (a typical PWR has a similar efficiency to that of the SMART reactor). This is likely due to the use of natural circulation of the reactor coolant in the NuScale design compared to the use of forced circulation in the SMART and typical PWR designs.

- It is expected that the smaller size of the NuScale reactor core compared to that of the SMART reactor and typical PWR will result in lower efficiency usage of the uranium fuel, and therefore have a somewhat higher fuel cost on a per MW-hr basis. The magnitude of this reduced efficiency and higher unit cost is unknown. However, the fuel cost of nuclear power reactors is small relative to the overall cost of nuclear heat/electricity generation, and small relative to similarly-sized fossil fuel plants. The contribution of the cost of the uranium fuel to the overall cost of nuclear power generation is discussed in a later section below.

- Historically, larger nuclear reactor modules were perceived to benefit from economies-of-scale. Specifically, the cost per unit of heat or electricity generated was believed to decrease with increasing energy production per module. However, there is now a recognized tradeoff that the increasing heat/electricity production of a single module comes at a cost of increased design complexity (e.g., more complex and additional safety systems) that potentially offsets these economies-of-scale.

[9] The NuScale reactor building includes the spent fuel pool, which is included in a separate auxiliary building for the SMART reactor and the typical PWR. While the dimensions of the NuScale spent fuel pool are unknown, it is estimated that the land area of the NuScale reactor building, excluding the land area of the spent fuel pool, is somewhat larger than the SMART reactor and typical PWR containment building.

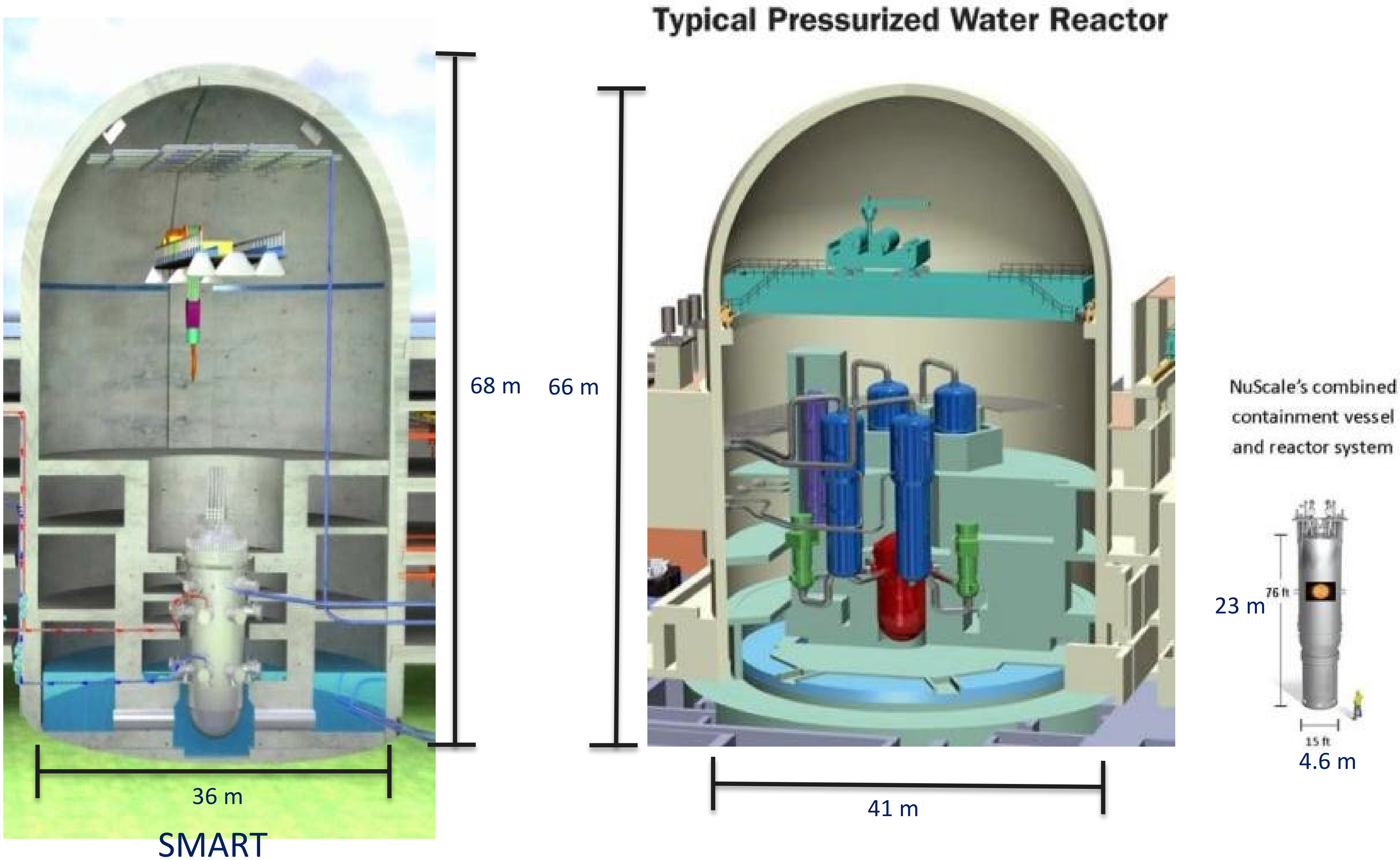

Figure 2-3. Comparison of the Reference iPWR Containment Designs to a Typical PWR

- Offsite factory fabrication of the reactor primary system as a mostly single module reduces the amount of on-site construction/installation of individual primary system components. However, the size and weight of the modules will likely be limited by available transportation infrastructure to the Alberta oil sands. For example, the NuScale NPM weighs 303 tonnes and the SMART RPV module weighs 750 tonnes.[10] The extent to which transportation of very large, heavy weight components may be an issue for SMR application in the Alberta oil sands is further addressed in Section 5 of this report.

2.3 Integration of iPWR into the Reference Facility Flowsheet

As discussed previously, Tetra Tech has developed material and energy flowsheets for the reference oil sands mine and extraction facility for four different scenarios: 1) PFT producing high grade bitumen product, 2) PFT producing low grade bitumen product, 3) NFT producing high grade bitumen product, and 4) NFT producing low grade bitumen product (Tetra Tech 2017). The flow sheets for each of these scenarios assume two GTGs are used to cogenerate the heat and electricity consumed in the reference facility. The amount of heat and electricity consumed in each scenario is summarized in Table 2-1.

For this evaluation, the reference iPWR was assumed to completely replace the two GTGs, and associated systems (i.e., heat recovery steam generators with duct burners and auxiliary boilers), to cogenerate the required heat and electricity. While each of the reference iPWR SMR technologies, NuScale and SMART, are specifically being designed to produce superheated steam and electricity using a steam turbine generator, engineering options exist for using the superheated steam product to produce the saturated steam streams needed for the oil sands mining facility application. While a feasibility assessment of potential design options is outside the scope of this study, options for consideration include:

1) Use steam heaters or reboilers to directly or indirectly transfer the heat in the superheated steam to separate working fluids (water). Of the options considered, this is likely the most economically feasible. Sub-options for accomplishing this include 1) diverting superheated steam destined for the turbine-generator to separate steam heaters or reboilers designed to produce the medium and low pressure steam streams, 2) use extraction steam from the steam turbine to supply heat to steam heaters or reboilers to produce the medium and low pressure steam streams (this option is more efficient than the former, however, it may not be able to provide the quantity of steam needed for the two streams), or 3) a combination of both of the above options.

   This option has previously been considered as a potential application of the CANDU reactor, a process diagram for which is provided in Figure 2-4 (IAEA 2007). From the IAEA report:

[10] In a typical large PWR, the individual RPV and reactor cooling system components that are incorporated in an SMR module are shipped and installed as individual components. As an example, several such components have been installed or will soon be installed at the AP1000 two-unit PWR (1100 MWe/unit) currently under construction in Georgia, USA, including 1) two RPVs each weighing 278 tonnes, 2) four steam generators each weighing 635 tonnes (two per unit), 3) two RPV heads each weighing 215 tonnes, and 4) two pressurizers each weighing 102 tonnes.

"There are two steam heaters operating at different pressures. The higher pressure [HP] one uses main steam directly from the SGs [reactor steam generators] and the lower pressure [LP] one uses extraction steam from the high-pressure turbine as a heating source to generate process steam at 2.0 MPa and 1.0 MPa. The process steam is piped to the bitumen extraction process and mostly used in mixture heat exchangers without condensate return. Therefore, feedwater to these steam heaters is mainly from the make-up water. The condensate from these steam heaters returns to the turbine's feedwater heating system. The thermal power of the process steam represents about 20% of total thermal power requirement. Therefore, the amount of the steam used in these steam heaters are not as significant as the low-pressure turbine extraction steam used in the water heaters."

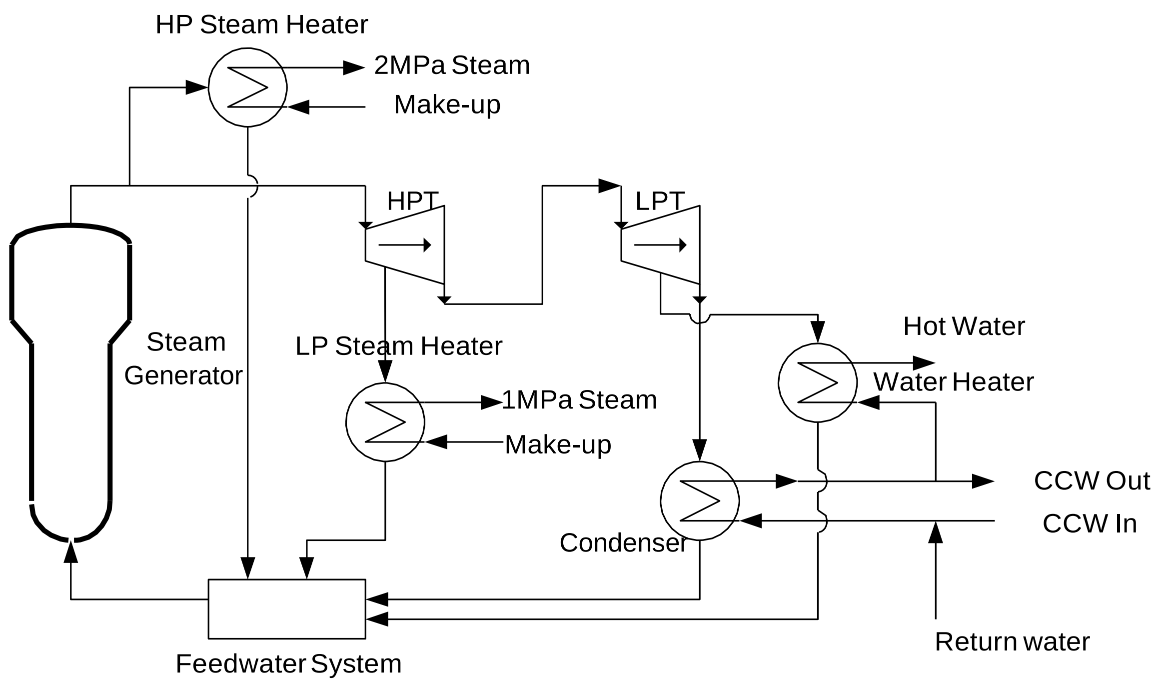

Figure 2-4. Process Diagram for a CANDU Adapted for Oil Sands Surface Mining

Because CANDU reactors produce steam having characteristics (about 4.7 MPa, 260^{o}C) similar to that of an iPWR, this figure is also generally applicable to iPWRs. While not specifically evaluated for the surface mining application, NuScale has developed similar process diagrams for non-electricity applications (NuScale 2014a, NuScale 2014b).

2) Downgrade the superheated steam using pressure-reducing or letdown valves. While likely feasible, the thermodynamic efficiency of this option would be expected to be lower than that of the previous option, which could increase the number of required reactor modules. However, this option is a simpler configuration than the previous option.

3) Generate the process steam using electric heaters supplied with electricity from the iPWR modules. Generating steam using electricity is generally recognized as an inefficient process. This is

particularly the case for iPWRs where steam is directly produced by the nuclear reactor system, which is then converted to electricity via turbine-generators.

4) Redesign the reactors to produce saturated steam rather than superheat steam. This is considered a much costlier option that would significantly reduce the economic benefits of standardized, factory-fabricated modules.

While development of mass and energy balance flow sheets with incorporation of the reference iPWR was beyond the scope of this project, an estimate was made of the number of NuScale and SMART modules needed to produce the electricity and steam consumed in the reference facility. These estimates assume no efficiency losses from letdown of the superheated steam produced by the iPWR to the reference facility saturated steam conditions, or from configuring the iPWR modules to produce the exact mixture of low pressure steam, moderate pressure steam, and electricity consumed in the reference plant. The number of iPWR modules was rounded up to the next highest integer, rather than assuming that the modules would be redesigned to match the exact need of the reference facility (which is not considered to be an economical option because of the costs associated with redesign of the reactor module and corresponding impacts to the factory fabrication process). It is assumed that any excess capacity can be supplied to the grid, or to be supplied as steam for local district heating or other uses.

Table 2-2 provides the estimated number of iPWR modules required to produce the electricity and steam consumed in the reference facility. The number of NuScale modules was estimated to range from six to eight, while the number of SMART modules ranged from three to four. While the cost implications of the number of modules is evaluated in the next section, basic economies-of-scale dynamics mean that the incremental cost of each additional module should be less than that of the preceding module. Larger economies-of-scale would be expected for a SMART reactor plant because each reactor module is contained within its own containment building and so each incremental module is essentially a replica of the previous module. For the NuScale plant, however, because all reactor modules are contained within a single reactor building, the capital cost of the reactor building would not be expected to change significantly with more or less modules. Hence, because of these difference in design approaches, the economic tradeoffs associated with the number of reactor modules is different between the two reactor concepts.

Table 2-2. Estimated Number of iPWR Modules Required

Bitumen Froth Treatment Method	Bitumen Grade	Number of NuScale Modules			Number of SMART Modules		
		Process Steam	Electricity	Total (Rounded)	Process Steam	Electricity	Total (Rounded)
Paraffinic Froth Treatment	High	2.6	2.8	5.4 (6)	1.3	1.3	2.5 (3)
	Low	4.3	3.9	8.2 (9)	2.1	1.8	3.9 (4)
Naphathanic Froth Treatment	High	2.3	2.8	5.1 (6)	1.1	1.3	2.4 (3)
	Low	3.2	3.9	7.1 (8)	1.6	1.8	3.3 (4)

While the most cost effective means of configuring the reference iPWR facility to produce the two process steam feeds and the electricity would be the subject of an optimization study, options for consideration include:

- Dedicate certain modules specifically to process steam production, others to electricity production, and still others to a combination of both process steam and electricity production. For example, for high grade PFT, if NuScale modules were to be used, two modules could be purpose-built for process steam production, two modules could be purpose-built for electricity production, and two modules could be purpose-built to produce both process steam and electricity, for a total of six modules.

- Configure all modules to produce both process steam and electricity. With this option, all modules would be configured to allow superheated steam to be diverted to electricity production, or to steam production, or to a combination of both. This option provides for the greatest flexibility but also has more system complexity than the former option. This is especially the case for the NuScale iPWR because it requires twice as many modules as the SMART iPWR.

Ultimately, the preferred configuration will depend on the choice of iPWR technology, the degree of system flexibility desired, and economics.

An important consideration that needs to be accounted for when using iPWR technology in an oil sands mining facility application is the availability and management of large quantities of water. Water requirements are much greater with iPWR technology than with GTG technology. iPWR technology uses the rankine cycle to produce electricity, which is water intensive because large quantities of low-pressure steam must be condensed for return to the plant's heat source for reboiling. The reference GTG technology uses the brayton cycle to produce electricity, which does not use water. The estimated amount of water required for a nuclear power plant based on LWR technology and using the rankine cycle is provided in the Table 2-3 for three different types of cooling systems typically used by LWRs (EPRI 2002).

Table 2-3. Amount of Water Required to Produce Electricity with LWR Technology

Cooling System Type	Cooling Water Withdrawal from River (tonnes/MW-hr)	Cooling Water Consumed Due to Evaporation (tonnes/MW-hr)
Once-Through Steam Plant Cooling	95 – 228	~1.5
Recirculated Steam Plant Cooling – Cooling Tower	3.0 – 4.2	~2.7
Recirculated Steam Plant Cooling – Cooling Pond	1.9 – 4.2	1.7 – 3.4

Assuming a recirculation cooling system is used in the iPWR application, the amount of required make-up water is estimated to be increased by 7 to 30% (240 to 730 tonnes/hr) over that reported in the Tetra Tech reference flowsheets. A larger impact, however, is the much greater amount of water required for the steam plant boiling/condensing cycle operations. It is estimated that water usage will increase by 50 to 280% (14,200 to 22,600 tonnes/hr) over that reported in the Tetra Tech reference flowsheets, requiring a significantly larger capacity recycled water pond.

To reduce the water usage, efficiency improvements could be considered, such as using the low quality waste steam from the turbine to preheat the feedwater for the steam heaters or boilers from the recycled water pond. This potential improvement has not been evaluated in this report.

2.4 Economics of iPWR Technology

Since no nuclear power plants have been built or operated to-date using iPWR technology, or any other advanced nuclear reactor technologies for that matter, there are no historical costs to report on this evolutionary technology. Hence, this section relies on published estimates of the cost of iPWR technology, with a specific focus on cost estimates that have published information on the underlying basis for the estimates and which provide sufficient breakdown of the cost estimate to draw insights on the significant cost contributors. For iPWR technology, the information reported here is primarily based on cost information developed and reported by NuScale Power LLC for the NuScale iPWR. Other cost estimates that are generally reported at a high level are provided for comparative purposes. Because there is no practical experience with either the factory fabrication of reactor modules, or with the construction and operation of iPWRs, the reader is cautioned that there is significant uncertainty with the cost estimates reported here.[11]

Three types of cost estimates for iPWRs are reported: 1) overnight capital cost (cost/kWe), which is the cost of a construction project if no interest was incurred during construction, 2) levelized cost of electricity (LCOE, cost/MW-hr), which is the cost of building, operating, and decommissioning the plant over an assumed financial life (a 40 year life is assumed in this study[12], unless otherwise indicated), and 3) levelized cost of steam (LCOS, cost/tonne steam), which is the LCOE multiplied by a design-specific conversion factor (MW-hr/tonne steam). While the oil sands mining facility application is not solely an electricity generation project, LCOE is used as a figure-of-merit in this study because of its common usage in comparing the cost of different types of electricity generation technologies. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, decommissioning costs, and an assumed capacity factor for the plant. The importance of each of these cost factors varies significantly between a nuclear power plant and a GTG plant.

[11] It is also noted that iPWR costs are expected to be higher for the oil sands mining and extraction facility application because construction and labor costs are generally higher in the northern locations of Canada where there is limited skilled labor and construction seasons are shortened due to frigid weather during the winter months. However, costs would similarly be higher for other energy sources, including GTG, to which the iPWR costs are compared. Hence, these factors are not specifically accounted for in the cost estimates presented in this section.

[12] The assumption of a 40 year life is a standard assumption when comparing different power generation sources. This is a conservative assumption because SMRs are generally being designed to operate for 60 years or longer. Hence, assuming an operating life of more than 40 years would improve the economics of the SMR technologies relative to GTG technologies.

Historically, capital/construction costs and O&M labor costs are comparatively much higher on an LCOE basis for nuclear power plants than for GTG plants, whereas O&M fuel costs are comparatively much higher for GTG plants than for nuclear power plants. Hence, the cost of GTG is highly sensitive to the cost of natural gas while nuclear costs are highly sensitive to capital costs and the cost of financing. This difference in the major cost contributors for new nuclear plants and new GTG plants is shown by the LCOE estimates provided in Table 2-4, which were developed by the U.S. Energy Information Agency (EIA 2016).

Table 2-4. Estimated LCOE for New Electricity Generation Plants

Plant Type	2015 US$/MW-hr			
	Levelized Capital Cost	**Fixed O&M**	**Variable O&M (including fuel)**	**Total LCOE**
GTG – Conventional Combined Cycle	12.8 – 13.9	1.4	41.2 – 41.5	55.4 – 56.9
GTG – Advanced Combined Cycle	15.4 – 15.8	1.3	38.1 – 38.9	54.7 – 56.0
New Large Nuclear Plants	75.0 – 78.0	12.4	11.3	98.7 – 101.7

The conventional combined cycle GTG plants utilize F5-class combustion turbines (702 MWe).
The advanced combined cycle GTG plants utilize the more efficient H-class combustion turbines (429 MWe).
The new nuclear plants assume two Westinghouse AP1000 PWR units (1117 MWe.each).

Overnight Plant Capital Cost

The overnight plant capital cost includes all costs for engineering, procurement, and construction (EPC) of the nuclear plant. It does not include interest incurred during construction. Project activities included in the EPC cost estimate are as follows:

- Reactor/containment building and associated systems and equipment, including reactor module(s), reactor cooling systems, and fuel handling systems
- Main control room/control building
- Radwaste (short for radioactive waste) building and associated systems for packaging, storage, and shipment of radioactive waste
- Used fuel storage pool and associated systems
- Turbine building and associated systems and equipment, including turbine-generators, steam condenser(s), etc.
- Balance of plant systems, structures, and components such as the cooling towers, water treatment facility, administration building, warehouses, security offices, radiological control access (RCA) entry, etc.

- Site infrastructure development and preparation

- Indirect costs such as construction services, field office and engineering services, home office and engineering services, temporary facilities, plant design costs, and plant startup costs

NuScale Power LLC has developed and reported an estimate of the overnight EPC cost for a 12-module NuScale iPWR plant. This estimate by cost category is provided in Table 2-5 (NuScale 2015). As reported by NuScale Power LLC, this cost is based on an extensive cost estimate development effort, including approximately 10,000 man-hours of effort, detailed equipment lists, updated construction plan, 84% of equipment pricing based on budgetary quotes, labor hours and rates based on Fluor construction project data, bottoms up indirect cost estimate, schedule based on 51 months mobilization to mechanical completion and 28.5 months from first safety concrete to mechanical completion, and Association for the Advancement of Cost Engineering (AACE) Class 4 (feasibility study using factored or parametric models) estimate with an accuracy range of +35% to -10%. The overnight EPC cost for the 12 module plant (570 MWe net) is US$5,078 /kWe (2014) or C$5,590 /kWe (2014).

Table 2-5. Estimated Overnight EPC Cost for a NuScale 12-Module iPWR

EPC Cost Category	2014 US $millions	% of Total Cost
12 Power Modules [first-of-a-kind (FOAK) Cost + Fee, Transportation & Site Assembly)	848	29
Home Office Engineering and Support	144	5
Site Infrastructure	60	2
Nuclear Island [reactor building (RXB), radwaste building (RWB), main control room (MCR)]	538	19
Turbine Island (2 buildings with 6 turbines each)	350	12
Balance of Plant (annex, cooling towers, etc.)	225	8
Distributables (Temporary Buildings, Field Staff, Construction Equipment, etc.)	545	19
Other Costs	185	6
Total Overnight Cost	**2,895**	**100**

KAERI has reported an estimate of the overnight EPC cost for a single module SMART iPWR (100 MWe) to be US$5800 /kWe (2007) (KAERI 2011b). However, no information was provided on the level-of-effort or detail that went into the development of this EPC cost estimate.

The analysis converts all cost estimates to the common year 2014 to allow for direct comparisons between estimates. Since the NuScale overnight EPC cost is already in 2014 dollars, no escalation to a different financial year is necessary. However, overnight cost estimates for the SMART iPWR was escalated to 2014 U.S. dollars using the average consumer price index (CPI) between 2007 and 2014. The overnight

EPC costs for both the reference iPWRS were then converted to Canadian dollars using an average 2014 exchange rate of 1.1 Canadian dollars per U.S. dollar.[13] From Table 2-2, for the oil sands mining and extraction application, the number of NuScale modules required is estimated to be between six and nine and the number of SMART modules is estimated to be between 2 and 3. The overnight cost estimate for the NuScale iPWR was scaled to the smaller number of modules from the basis cost estimate for a 12-module plant using EPC cost category-specific scaling factors developed by PNNL. The overnight cost estimate for the SMART iPWR was scaled to the larger number of modules from the basis cost estimate for a single module plant assuming twin units are 20% more economical (KAERI 2013). The resultant overnight cost estimates for both the NuScale and SMART iPWR plants are provided in Table 2-6. The overnight EPC costs are similar for the two iPWR concepts after costs are normalized to the same electrical capacity (6 – 9 modules for NuScale and 2 – 3 modules for SMART).

Table 2-6. Comparison of Overnight EPC Cost for NuScale and SMART iPWR Plants

iPWR Plant	2014 US$ per kWe	2014 C$ per kWe
NuScale iPWR		
12-Module Plant	5,100	5,600
6 – 9 Module Plant	5,300 – 5,500	5,800 – 6,000
SMART iPWR		
Single Module Plant	6,600	7,300
2 – 3 Module Plant	5,500	6,100

LCOE/LCOS

The LCOE includes the following:

- EPC overnight cost (discussed above)
- EPC (capital) financing costs, including debt financing (interest) and equity financing (return on investment) as applicable
- operations and maintenance (O&M) costs, which includes annual fixed costs (e.g., labor, regulatory fees, supplies and services, insurance) and variable costs (e.g., refueling outages, unplanned plant shutdowns/outages for repairs)

[13] It is recognized that the use of a single escalation factor for all of the cost categories is overly simplistic and not very accurate on an individual cost category basis. However, on an aggregate overnight cost basis this approach is judged to provide a reasonable approximation that is accurate to within a few percent of what the result would be with a more detailed analysis.

- nuclear fuel and used fuel management costs, which includes purchase of new fuel (e.g., uranium, uranium enrichment services, fuel fabrication) and storage and eventual disposition of used nuclear fuel (e.g., long term interim storage, permanent disposition/disposal of used fuel)

- taxes, which includes income and property taxes

- plant decommissioning costs

- owner costs, which includes for example human resource support and management, central office, plant licensing and permitting, annual regulatory inspections and oversight, legal fees, switchyard, project development, engineering services, contingency

NuScale Power LLC has developed and reported an estimate of the LCOE for a 12-module NuScale iPWR plant. This estimate by cost category is provided in Table 2-7 (NuScale 2015). Other than the limited estimating assumptions provided in this table, little information was provided on the assumptions used in the development of this estimate. The LCOE cost for the 12 module plant (570 MWe net) is $114 /MW-hr (2015 US$).

Table 2-7. Estimated LCOE for a NuScale 12-Module iPWR

LCOE Cost Category	2015 US$ per MW-hr	% of Total LCOE
Capital [assumes financing is 55% debt (at interest rate of 5.5%) and 45% equity (at rate of return of 10%)]	52	46
O&M [assumes 360 full-time equivalent (FTE) staff]	24	21
Nuclear Fuel and Spent Fuel Disposition	14	12
Taxes (including income and property)	18	16
Owner Costs	6	5
Decommissioning	0.3	0.3
Total LCOE	**114**	**100**

KAERI's most recent reported LCOE estimate for the SMART was $61 /MW-hr (2007 US$) (KAERI 2011b). No further information was provided on the basis for this cost estimate. However, this LCOE estimate is exceptionally low given the US$5800 /kWe (2007) overnight EPC cost estimate by KAERI discussed previously. Hence, it appears that the LCOE was estimated using a methodology that is different than is used throughout this study, and so is not used further in this study.

While limited information is available on the specific underlying basis-of-estimate for the LCOE breakdown provided in Table 2-7, the following observations can be made about important cost drivers:

- Of the US$52 /MW-hr capital cost contribution, more than 30% is for the overnight cost of $2.895 billion and the remaining 70% is financing cost.

- Of the US$24 /MW-hr O&M cost contribution, more than 40% is for the assumed staffing level of 360 full-time equivalent (FTE) staff (discussed further in Section 2.5), another 40% is for the cost of periodic refueling and maintenance outages, 8% is for annual capital improvements to the plant, and the remaining 12% is for utilities, support services, supplies, regulatory and other fees, and taxes and insurance.

- Of the US$14 /MW-hr new fuel and spent fuel disposition contribution, about 93% is for the purchase of new fuel and the remaining 7% is for spent fuel disposition. It is unlikely that significant cost reductions are possible with this category because the cost of new nuclear fuel has been depressed the last few years, is likely to stay depressed for the foreseeable future, and is already a small contributor to the cost of nuclear power.

- The US$18 /MW-hr for taxes will be a site specific assumption. Never-the-less, the LCOE contribution assumes a tax rate of about 35%, which is consistent with the 39% tax rate assumed in the Canadian Energy Systems Analysis Research (CESAR) assessment of scenarios for reducing annual GHG emissions from oil sands production using SAGD (CESAR 2016).

No escalation of the NuScale iPWR LCOE was required since these costs were in 2015 dollars and the inflation rate between 2014 and 2015 was 0.1% in the U.S., so 2014 and 2015 year dollars are essentially the same. LCOE estimate was then converted to Canadian dollars using an average 2014 exchange rate of 1.1 Canadian dollars per U.S. dollar. From Table 2-2, for the oil sands mining facility application, the number of NuScale modules required is estimated to be between six and nine. The LCOE estimate for the NuScale iPWR was scaled to the smaller number of modules from the basis cost estimate for a 12-module plant using LCOE cost category-specific scaling factors developed by PNNL. The resultant LCOE estimates for the NuScale iPWR plant is provided in Table 2-8. Estimates of the LCOS are also provided using a design-specific conversion factor. Also provided in able 2-8 is the levelized cost of steam produced (cost/tonne steam).

Table 2-8. Estimated LCOE and LCOS for NuScale and SMART iPWR Plants

iPWR Plant	2014 US$ per MW-hr	2014 US$ per tonne steam	2014 C$ per MW-hr	2014 C$ per tonne steam
NuScale iPWR				
12-Module Plant	114	22.4	125	24.7
6 – 9 Module Plant	118 – 124	23.3 – 24.4	130 – 136	25.6 – 26.8

For comparison, an SMR industry organization in the U.S. recently estimated the LCOE for the first SMR to be C$130/MW-hr (2017) for an investor-owned plant and the overnight EPC cost to be C$5,750/kWe (2017), with the expectation that these costs will decrease as additional SMRs are built (SMR Start 2017). These estimates are similar to those estimated in this study for iPWR SMRs.

2.5 iPWR Staffing Levels

As discussed previously, no nuclear power plants using iPWR technology have yet been built. Hence, as with overnight EPC cost and LCOE, staffing levels developed by the reactor vendors are engineering estimates based on expected performance of the evolutionary technology, which generally involves a significant reduction, relative to current operating nuclear plants, in the number of safety and non-safety plant systems requiring operations and maintenance staff. Of the two reference iPWRs evaluated in this report, only NuScale Power LLC has publicly released an estimate of the number of FTEs needed to operate, maintain, and manage the plant after startup. The estimate is 360 FTEs for a 12-module NuScale iPWR (NuScale 2015). NuScale Power LLC, however, did not provide a breakdown of the 360 FTE estimate for the 12-module NuScale iPWR.

Generation mPower LLC also developed staffing estimates for the mPower iPWR, see Phase I report (PNNL 2016) and Appendix A of this report, for a two-module plant (360 Mwe) and a four-module plant (720 MWe). The staffing estimates for these two plant configurations were 298 FTEs and 427 FTEs, respectively (Generation mPower 2013). The NuScale Power LLC estimate of 360 FTEs for a 12-module 570 MWe plant is very consistent with the staffing estimates for the mPower iPWR. The Generation mPower LLC staffing estimates were based on a 2004 study by Dominion for the U.S. Department of Energy in which staffing estimates were developed for several advanced reactor designs (Dominion 2004). Given the consistency between the staffing estimates for the NuScale and mPower iPWRs, this study also utilized the 2004 Dominion study to develop a breakdown of the staffing estimate for the NuScale iPWR. While the result will clearly not be the same as NuScale Power LLCs estimate, it is believed that the insights on the dominant staffing categories will be consistent and so the results should be considered from this perspective. Since there is no baseline staffing level available for the SMART iPWR, no similar estimate is developed for this reactor.

The estimated FTE division amongst labor categories for the NuScale 12-module plant is provided in Table 2-9. This staffing level assumes a five-shift, around-the-clock operation of the plant. O&M and security staff compose almost half of the FTEs.

2.6 Comparison with GTG Cogeneration Technology

CESAR estimated the LCOE for several scenarios postulated to reduce the annual GHG emissions from oil sands production using SAGD (CESAR 2016). While the CESAR analysis specifically assessed scenarios to reduce GHG emissions from SAGD operations, the LCOE for each scenario was estimated for the entire Alberta electric Grid and so the results are applicable for comparison to the cost of iPWR technology to reduce GHG emissions from oil sands mining and extraction. The results shown in Figure 13 of the CESAR report show the LCOE for all of the scenarios to be about C$95/MW-hr (2014) in the 2020 time frame and decreasing to about C$80/MW-hr (2014) in the 2030 time frame[14], which includes an assumed carbon or GHG price of C$30/tonne CO_2. This assessment was based on an overnight EPC

[14] The CESAR study assumed the cost of natural gas to be 2014 C$3.25/GJ, and would hold steady from 2016 through 2030.

cost of a natural gas cogeneration plant of C$1750/kWe (2014), which is substantially less than that of an iPWR.

Table 2-9. Estimated Number of FTEs for a NuScale 12-Module iPWR

Labor Categories	Number of FTEs	% of FTE Total
Management	7	2
O&M	89	25
Engineering	45	13
Outages and Plant Modifications	41	11
Operations Support and Oversight	21	6
Radiation Protection	42	12
Staff Training	17	5
Security	84	23
Supplies and Telecommunications	15	4
Total LCOE	**360**	**100**

The LCOE for the reference iPWR plant, as reported in Table 2-8, ranges from C$125/MW-hr (2014) for a 12-module plant to C$130-136/MW-hr (2014) for a six to nine-module plant sized to supply the electricity and process steam requirements for the reference oil sands mining and extraction facility. The LCOE for the reference iPWR is therefore C$30-60/MW-hr (2014) higher than natural gas cogeneration (assuming the cost of iPWR technology doesn't correspondingly decrease between now and 2030). Assuming no reductions or improvements in the cost of iPWRs, it is estimated that the price of natural gas would have to increase to C$7.5-8.0/GJ for iPWRs to become economically competitive with natural gas cogeneration.

Figure 2-5 provides a "representative" breakdown of the LCOE cost for both iPWR and natural gas cogeneration plants.[15] The intent of this figure is to provide a relative comparison of the two technologies for the purpose of identifying the major reasons for the differences between the two. To develop this figure, component costs for natural gas cogeneration (CESAR 2016) and component costs for a generic SMR (SMR Start 2017) were used to develop the LCOE using the CESAR LCOE formula (CESAR 2016). Hence, the costs reported in this figure are somewhat different than those reported above. The most significant reason for the difference in LCOE between the two technologies is the significantly higher capital cost of iPWR plants compared to that for cogeneration plants. The operating cost of an

[15] The term "representative" is used to denote a single point estimate of the LCOEs for iPWR and natural gas cogeneration technologies using the same LCOE formula for both technologies. The ranges of LCOEs reported elsewhere in this report were generally developed in the respective references cited for these estimates, and escalated to a common year and/or converted to Canadian currency as necessary, and so reflect different assumptions in the LCOE estimates. The "representative" estimates were developed using common assumptions, such as the same LCOE formula, tax rate, discount rate, etc., based on available information. For this reason, the total LCOEs reported in Figure 2-5 for both iPWR and natural gas cogeneration are somewhat different (lower) than those developed from the cited references.

iPWR (excluding fuel) is also significantly higher than that for a cogeneration plant, however, this is largely offset by a much higher fuel cost for the cogeneration plant than for an iPWR plant.

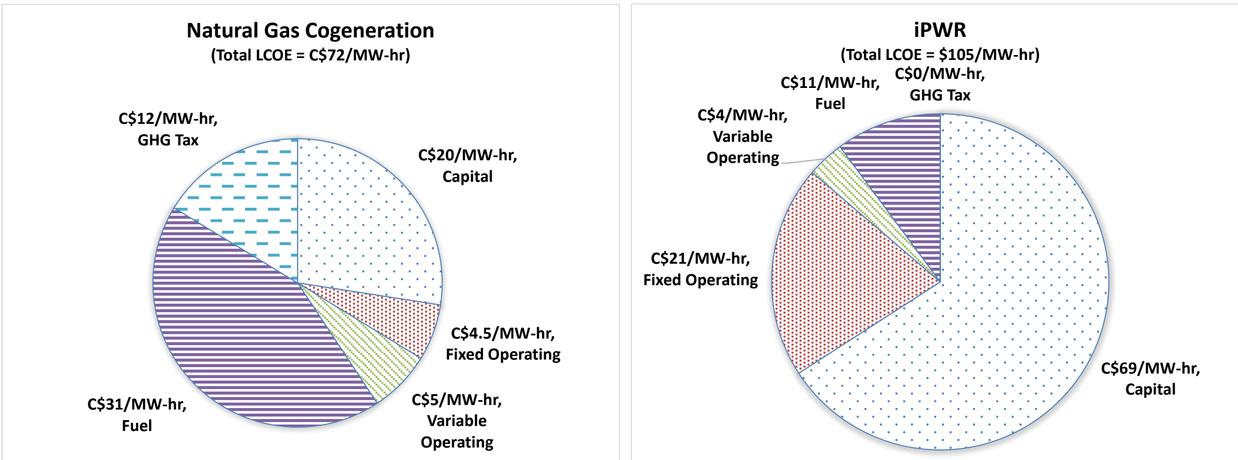

Figure 2-5. Comparison of Representative LCOE (2017) for iPWR and Natural Gas Cogeneration

2.7 Improving the Economic Competitiveness of iPWR Technology

Improving the economic competitiveness of iPWRs relative to GTGs in providing the electricity and steam required for oil sands mining and extraction is a significant challenge with today's natural gas prices that are near historical lows. The following identifies potential opportunities to improve the economics of iPWRs:

- Financing costs. The much lower LCOE for a GTG plant relative to an iPWR is largely due to the current low price of natural gas; the current Henry Hub spot price for natural gas is at or near historical lows. The cost of natural gas is the largest single contributor to the LCOE for modern GTG plants, while the largest single contributor to the LCOE for an iPWR is the initial capital investment to construct/commission the plant and associated cost of financing. As noted in Section 2.4, the LCOE for an iPWR can be reduced by 30% or more by obtaining better financing conditions (i.e., reduced interest rate/return on investment).

  Reducing the construction schedule would also reduce financing costs incurred prior to plant operation. The LCOE for the reference (NuScale) iPWR assumed a construction schedule of about four years from mobilization until construction completion, with about 2.5 years required for critical path nuclear safety-related construction. This is a fairly ambitious construction schedule that has yet to be demonstrated in locations having moderate temperature climates much less in northern climes.

- Overnight EPC Costs. A breakdown of the overnight EPC cost for an iPWR plant is provided in Figure 2-6. The overnight EPC cost for the reactor module and associated reactor/containment building contribute about 50% of the total EPC cost of the reference iPWR. This EPC cost was for a FOAK plant, which would be expected to decrease with an n^{th}-of-a-kind (NOAK) plant using a standardized reactor design.[16] If the overnight EPC cost of a NOAK plant was 20% less than that of the FOAK plant, the LCOE would decrease by about 9%.

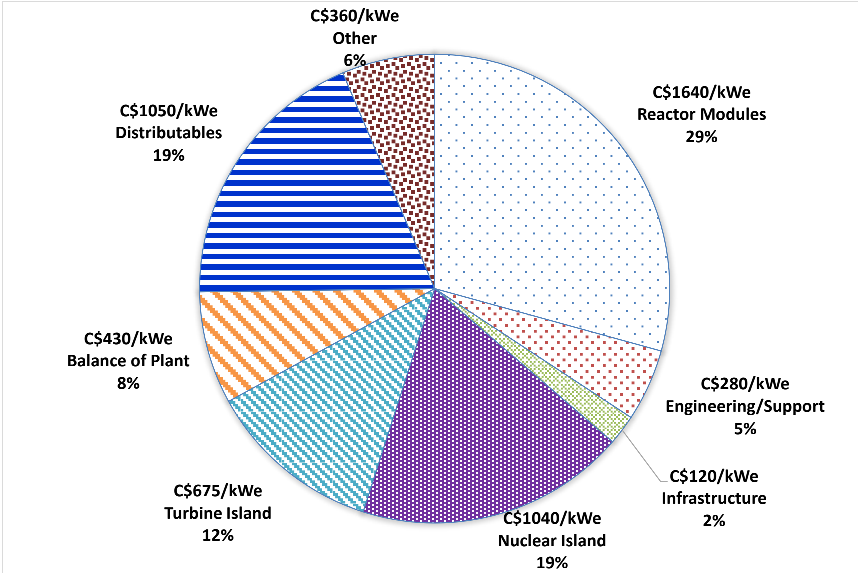

Figure 2-6. Overnight EPC Cost (2014) of an iPWR Plant (C$5600/kWe)

- Number of FTEs. O&M and security FTEs are estimated to contribute about 50% of the total plant operating staff estimate of 360 FTEs for the reference iPWR. While this staffing level is reduced from current generation PWR power plants due to credit for advanced passive/intrinsic safety/security features and automation of control and monitoring systems, it is still high relative to the staffing level of 50-60 FTEs required to operate a typical GTG plant. Staffing levels for iPWRs are, to some extent, driven by regulatory requirements to ensure safe/secure operation of the plant, and current generation PWR operating experience, which potentially could be reduced with a FOAK plant based on operational experience. If the staffing levels for a NOAK plant was 33-50% less than that of the NOAK plant, the LCOE would decrease by about 3-4%.

- Turbine Island. The cost of the reference iPWR is for a plant that utilizes all of the produced steam generate electricity. However, for a surface mining facility, only about half of the plant is needed to generate electricity, while the superheated steam for the remaining half is used to generate process steam. Hence, the turbine-generator plant only needs to be half the size assumed in the LCOE estimate. On the other hand, this reduced requirement is offset by the need for other equipment/systems (steam heaters or reboilers) to convert the superheated steam to saturated

[16] The definition of the "NOAK" plant is not well established, and is subject to a variety of factors, including the extent to which the vendors/suppliers were involved with the design/construction of previous plants, the number of modules incorporated in previous plants, and site-specific variables that impact design and construction. A typical definition is that the NOAK plant is the fifth or higher plant constructed and operated (DOE 2012).

process steam having the appropriate pressure and temperature. If the overnight EPC cost of the turbine island is reduced by 50%, the LCOE would decrease by about 3%.

- Distributables (Temporary Buildings, Field Staff, Construction Equipment, etc.) are estimated to be about 19% of the overnight EPC cost of the reference iPWR plant. Since the oil sands mining and extraction facility is a large industrial facility, it may be possible to reduce the cost of distributables by sharing these costs with the mining and extraction facility. If the overnight EPC cost of distributables is reduced by 50%, the LCOE would decrease by about 4%.

- Accident-tolerant Fuels. Severe accidents, such as those at the Three Mile Island Unit 2 plant in 1978 and the Fukushima Daiichi plant in 2011, have raised public awareness of the potential risks with nuclear power. These accidents demonstrated that under extreme conditions, the nuclear fuel will fail resulting in severe damage to the plant and, potentially, the release of large quantities of radioactive material. Recognizing the vulnerability of current LWR fuel designs to severe accident conditions, there is considerable on-going world-wide research into developing advanced fuel designs that are more accident-tolerant than the current fuel designs. While the iPWRs evaluated in this study have already incorporated many innovative design features to significantly reduce the likelihood of a severe accident relative to that of current generation LWRs, the use of advanced accident-tolerant fuel designs could further improve the safety and the economics of LWRs, including SMRs.

3.0 Alberta Oil Sands SAGD Application

There are two principal methods used to extract bitumen from the Alberta oil sands: 1) surface mining of the oil sands followed by bitumen extraction and froth treatment and 2) in-situ recovery of the bitumen using processes such as steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). With either method, the resultant bitumen product may need to be upgraded to synthetic crude oil (SCO), which has the effect of reducing viscosity and increasing the hydrogen to carbon ratio thus enabling pipeline transportation without the need for diluent addition while increasing market value. This section of the report assesses the potential for using SMRs to provide the steam and electricity requirements for in-situ recovery of oil using SAGD. The potential application of SMRs for surface mining of bitumen and for hydrogen production for bitumen upgrading are assessed in other sections of this report.

For the purposes of this assessment, the base case oil sands SAGD central processing facility developed by Candor Engineering (Candor Engineering 2017) was utilized as the reference facility. The reference facility is a fictitious stand-alone SAGD central processing facility, having a bitumen (dilbit) production rate of 33,000 barrels per day (bbl/d). A material and energy flow diagram was developed for the reference facility. The steam and electricity consumption for the reference facility is provided in Table 3-1.

Table 3-1. Steam and Electricity Consumption for Reference SAGD Facility

High Pressure Steam (10 MPaG, 225ºC)		Low Pressure Steam (1.05 MPaG, 210ºC)		Power Consumption
Mass (tonnes/hr)	**Heat (GJ/hr)**	**Mass (tonnes/hr)**	**Heat (GJ/hr)**	**MWe**
655	1556	15	35	18

The reference facility is assumed to utilize natural gas-fired once through steam generators (OTSGs) to generate the steam consumed in the facility. Approximately 90% of the GHG emissions associated with SAGD oil sands extraction are due to natural gas consumption. Based on a requirement to be capable of producing steam having the minimum characteristics defined in Table 3-1, and considering other criteria, a reference SMR technology was selected and integrated into the reference SAGD facility flowsheet, replacing the OTSGs. The economics of the reference SMR were then evaluated and compared to the reference OTSG technology.

3.1 Selection of the Reference SMR Technology

The criteria defined for selecting the reference SMR technology for the oil sands SAGD facility application are as follows:

- The steam characteristics and steam/electricity production meet the reference facility requirements defined in Table 3-1, with the primary requirement being capable of producing the high pressure steam.

- The technology readiness level (TRL), as defined in Section 2.1 of this report, is sufficiently high (TRL of 5 or greater) as to support implementation in the oil sands by the year 2030.

- Investment in development and demonstration of the technology by the reactor vendor appears to be sufficient to support commercialization and implementation by the year 2030.

- Advanced passive/inherent safety features are incorporated into the reactor design, thus minimizing operational complexity and the associated nuclear-qualified operations/maintenance staffing that would need to be located in the harsh northern Alberta climate.

Based on assessment of each of the 26 SMR concepts evaluated in Phase 1 relative to these criteria, which are summarized in Appendix A of this report, HTGR technology was selected as the reference SMR technology for the SAGD facility application. This selection was based on the following considerations:

- HTGRs are capable of producing the electricity and process steam requirements defined in the reference flowsheet, as defined in Table 3-1.[17] HTGRs are generally being designed to produce high temperature helium gas that is coupled to a gas turbine generator to produce electricity (Brayton Cycle). However, several HTGR designs incorporate a steam generator that utilizes the high temperature helium gas to produce superheated steam (Indirect Rankine Cycle) having characteristics of 12.5 – 16.7 MPa and 538 – 566°C. Since the steam may need to be piped over significant distances to the injection wells, having superheated steam is ideal for the SAGD application.

- While iPWR technology is based on PWR technology that has over 50 years of operating experience representing thousands of reactor years of operation, it is not capable of directly producing the high pressure steam required for the SAGD application (see Section 2 for iPWR steam temperature/pressure characteristics). The Phase I report (PNNL 2016) discussed options for upgrading the steam produced from iPWRs to that required for SAGD applications. However, this would further increase the cost of using iPWR technology which, as discussed in Section 2.6, already has a significant cost disadvantage relative to GTG technology.

- While HTGR technology is not used in any currently operating nuclear power plants, several demonstration plants have been built and operated in the past, including the 330 MWe Fort St. Vrain plant in the U.S. that generated electricity for over 10 years before being decommissioned in 1989 (see the Phase I report for additional information on these past reactors). Hence, there is a significant amount of design and operational experience with HTGR technology, including HTGR fuel technology referred to as TRISO fuel. Because TRISO fuel cannot melt down in a

[17] The potential application of HTGR technology in the oil sands to recover oil using SAGD has been extensively evaluated in previous studies and shown to be feasible. See the following references: SNC•Lavalin 2008, MPR Associates 2009, and INL and PTAC 2011.

severe accident, HTGRs are the only nuclear power technology generally recognized as being inherently safe. All of the HTGRs currently under active development utilize TRISO fuel. A significant amount of the rigorous qualification testing required to demonstrate TRISO fuel meets regulatory performance requirements has been completed or is currently in progress.

- For many of the HTGR designs, the vendors are making significant investments in the technology. Specifically, investments are being made in the HTR-PM (China), StarCore (Canada), SC-HTGR (USA), and Xe-100 (USA). Furthermore, the two-unit HTR-PM reactor is currently under construction and expected to start operation in the spring of 2018 and StarCore has submitted an application to the Canadian nuclear regulator for pre-licensing design review.

- Little information is available on expected staffing levels for HTGRs and SMRs generally. The inherent safety features in HTGRs are expected to result in a significant reduction in the FTE staffing levels relative to that required by current generation PWR technology. Based on the lack of staffing information, however, this criterion is not a discriminator for selecting the reference SMR.

3.2 Overview of the Reference HTGR

For the purposes of this evaluation, the SC-HTGR SMR and the StarCore SMR are used as the reference HTGRs for the oil sands SAGD facility application. There are three principal reasons for this: 1) each is one of the four HTGR designs identified in the previous section that are receiving significant investment, 2) the StarCore HTGR concept ranked the highest in the Phase I report (PNNL 2016) for SAGD application in the Alberta oil sands, and 3) of the HTGR design concepts, the SC-HTGR design has the most comprehensive information available in the open literature on the design, including details on preliminary estimates of its economics and staffing levels. However, the reader is cautioned that these HTGR designs, like all of the HTGR designs, are still in the development phase and so there is no practical experience with the construction and operation of these next generation HTGR designs. A brief overview of each of the two reference HTGRs is provided below.

SC-HTGR (Steam Cycle High-Temperature Gas-Cooled Reactor) by AREVA [USA]

The SC-HTGR is a modular prismatic block type HTGR having a design electrical/thermal capacity of 272 MW_e/625 MW_{th}. The primary circuit of each reactor module consists of the Reactor Vessel coupled to two Steam Generators, each of which has a dedicated helium coolant Main Circulator. A cross vessel connects each steam generator to the reactor vessel. The reactor vessel contains the reactor core, reactor internals, and control rods. The entire primary circuit is housed within a conventional steel vessel referred to as the Reactor Silo. The reference plant, after the first-of-a-kind built plant, is designed to contain four reactor modules. Figure 3-1 provides a conceptual drawing of the SC-HTGR reactor system and silo configuration.

Like the other HTGRs discussed in this report, the reactor core is cooled by the forced circulation of helium coolant and the neutron moderator is high-density reactor-grade graphite. Passive safety features allow for the passive removal of decay heat for an unlimited time period without safety-related emergency AC/DC power, additional coolant, pumps, or operator actions. The Reactor Silo, containing the entire primary system including the RPV, is located below ground.

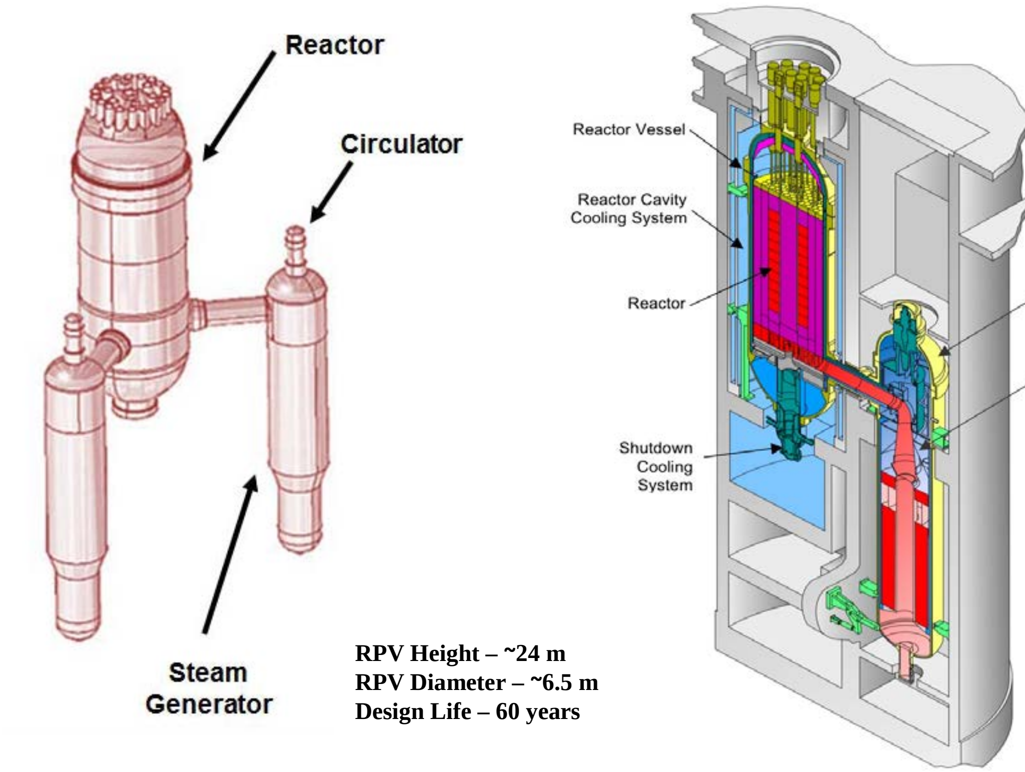

Figure 3-1. Conceptual Drawing of SC-HTGR Reactor System and Silo (AREVA 2014)

The design of this reactor builds on the experience base of past prismatic-block type HTGR plants, principally the Fort St. Vrain and Peach Bottom Unit 1 plants in the U.S. The conceptual design has been completed and the Pre-Licensing Application is being prepared for submission to the U.S. NRC. No schedule has been announced for delivery of a design certification application to the U.S. NRC. The NGNP (Next Generation Nuclear Plant) Industry Alliance is in the process of selecting a location and determining the funding source for the demonstration plant, which is planned to be operational in the mid-2020s. Based on this, the SC-HTGR is judged to have a TRL of 5-6 and an estimated commercialization time window of 10-15 years.

Information in this section and additional information about the SC-HTGR can be found in the following references: IAEA September 2014, NGNP Industry Alliance Limited 2013, NGNP Industry Alliance Limited June 2015, NGNP Industry Alliance Limited August 2015, NGNP Industry Alliance Limited 2016, AREVA 2014, Nuclear Plant Journal 2014, INL April 2011a, INL 2016, Global Trade Media 2012, and ANS 2014.

StarCore Co-Generation High Temperature Gas Reactor by StarCore Nuclear [Canada]

The StarCore is a modular prismatic block type HTGR containing two reactor modules per plant and having a total plant design electrical/thermal capacity of 20 MW_e /50 MW_{th}, with an additional 10 MW_{th} dedicated to non-electrical uses (e.g., district heating). There is no publicly-available schematic of the reactor core and primary cooling system, and PNNL is not aware of any publicly-available information on this reactor design other than the high-level description provided here. The primary system is composed of the RPV containing the reactor core, control rods, the first stage Energy Transfer System (ETS-1) that uses helium gas for cooling the reactor, and the first Intermediate Heat Exchanger (IHX-1). The reactor is contained in a modified fuel shipment container that, after transportation from the factory to the plant site, is installed in a steel canister silo that is contained within a double-walled higher performance concrete silo.

The reactor core is cooled by the forced circulation of helium coolant and the neutron moderator is high-density reactor-grade graphite. Passive safety features allow for the passive removal of decay heat for an unlimited time period without safety-related emergency AC/DC power, additional coolant, pumps, or operator actions. The reactor is installed 57 meters underground to provide enhanced containment and security. A unique aspect of the reactor concept is that the reactor/reactor core is described as being shipped to the site in a single shipment container, installed as described above in a concrete silo, and is removed every 5 years to the reactor vendor site for refueling and/or decommissioning (hence, no on-site operators specialized in refueling operations are required and minimal radiological decommissioning activities would be expected). Another unique aspect of this reactor concept is that reactor operations are described as being monitored remotely from the reactor vendor's plant and so on-site nuclear operators are not necessary (although some monitoring personnel are expected to be located at the reactor site). Personnel needed to operate the non-nuclear balance-of-plant (BOP), including thermal/electric plants, will be located at the reactor site. Also, because of the inherent/passive safety features of the reactor, another claimed feature of this reactor concept is that the reactor site will be publicly-accessible with no overt security fences or guards.

No schedule has been announced for submission of the design certification application to the Canadian Nuclear Safety Commission (CNSC), although StarCore has applied for pre-licensing vendor design review by CNSC. There have been no announcements of any significant funding or funding partners. Furthermore, there has been no published schedule for the performance of component/fuel testing, although StarCore may be relying on previous experience with TRISO fuel. Finally, PNNL believes certain aspects of the concept pose difficult technical/licensing challenges for implementation by 2030: (1) licensing the reactor vessel as a transportation container/package for the fuel/used fuel, (2) remote monitoring and operation of the reactor, (3) away-from-reactor centralized storage of the used fuel, and (4) publicly-accessible reactor site with no overt security features. Based on this, the StarCore is judged to have a TRL of 1-2 and an estimated commercialization time window of 15-20 years.

Information in this section and additional information about StarCore can be found in the following references: StarCore Nuclear 2016, Hatch 2014.

3.3 Integration of HTGR into the Reference Facility Flowsheet

As discussed previously, Candor Engineering has developed material and energy flowsheets for the reference SAGD facility (Candor Engineering 2017). The flow sheet assumes the high and low pressure steam consumed in the facility is provided by six natural gas-fired OTSG boilers and the electricity is provided from the grid. The amount of heat and electricity consumed in each scenario is summarized in Table 3-1.

For this evaluation, the reference HTGR was assumed to completely replace the six gas-fired OTSG boilers to generate the required high and low pressure steam, with specific focus on generating the high pressure steam. The reference HTGR could also be used to generate the electricity consumed in the facility, but given the small amount required the focus of this study is on generating the high pressure steam. While each of the reference HTGR SMR technologies, SC-HTGR and StarCore, are specifically being designed to produce superheated steam, as discussed in Section 2.3, there are several engineering options for using the superheated steam to produce the saturated steam needed for the SAGD facility application. A feasibility assessment of the potential design options is outside the scope of this study, however, the use of steam heaters or reboilers to directly transfer the heat in the superheated steam to separate working fluids (water) appears to be a particularly feasible option.

While development of mass and energy balance flow sheets with incorporation of the reference HTGR was beyond the scope of this project, an estimate was made of the number of SC-HTGR and StarCore modules needed to produce the steam consumed in the reference facility. These estimates assume no efficiency losses from letdown of the superheated steam produced by the HTGR to the reference facility saturated steam conditions. The number of HTGR modules was rounded up to the next highest integer, rather than assuming that the modules would be redesigned to match the exact need of the reference facility (which is not considered to be an economical option because of the costs associated with redesign of the reactor module and corresponding impacts to the factory fabrication process). It is assumed that any excess capacity can be supplied to the grid, or to be supplied as steam for local district heating or other uses.

One SC-HTGR module was estimated to be sufficient to generate the required process steam, while 18 StarCore modules were estimated to be required.

3.4 Economics of HTGR Technology

It has been over 25 years since a nuclear power plant using HTGR technology has operated anywhere in the world (although there are research/demonstration reactors using HTGR technology currently operating), and none of the HTGR SMR discussed in the Phase I report (PNNL 2016) have been built or operated to-date (although construction of the two unit demonstration HTR-PM HTGR in China is nearing completion and startup is expected in Spring 2018). Hence, there are no recent historical costs to report on this technology. This section therefore relies on published estimates of the cost of HTGR technology, with a specific focus on cost estimates that have published information on the underlying basis for the estimates and which provide sufficient breakdown of the cost estimate to draw insights on the significant cost contributors. For HTGR technology, the information reported here is primarily based on cost information developed and reported by Idaho National Laboratory (INL) for the Next Generation Nuclear Plant (NGNP), which is a similar design concept and thermal/electrical capacity to the SC-HTGR, and for the GT-HTR300 by Japan Atomic Energy Agency (JAEA), which is described in the Phase I report (PNNL 2016). Other cost estimates that are generally reported at a high level are provided for comparative purposes. Because there is no practical experience with either the factory fabrication of reactor modules, or with the construction and operation of HTGR SMRs, the reader is cautioned that there is significant uncertainty with the cost estimates reported here.[18]

Three types of cost estimates for HTGRs are reported: 1) overnight capital cost (cost/kWe), which is the cost of a construction project if no interest was incurred during construction, 2) LCOE (cost/MW-hr), which is the cost of building, operating, and decommissioning the plant over an assumed financial life (a 40 year life is assumed in this study, unless otherwise indicated), and 3) levelized cost of steam (LCOS, cost/tonne steam), which is the LCOE multiplied by a design-specific conversion factor (MW-hr/tonne steam). While the oil sands SAGD application is not an electricity generation project, LCOE is used as a figure-of-merit in this study because of its common usage in comparing the cost of different types of electricity generation technologies and because this is the metric used in a recently completed study evaluating replacing the OTSGs with cogeneration GTGs having heat recovery steam generators (HRSGs) (CESAR 2016). Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, decommissioning costs, and an assumed capacity factor for the plant. The importance of each of these cost factors varies significantly between a nuclear power plant and a GTG plant.

As discussed in Section 2.4, capital/construction costs and O&M labor costs are comparatively much higher on an LCOE basis for nuclear power plants than for GTG plants, whereas O&M fuel costs are comparatively much higher for GTG plants than for nuclear power plants. Hence, the cost of GTG is highly sensitive to the cost of natural gas while nuclear costs are highly sensitive to capital costs and the cost of financing. This difference in the major cost contributors for new nuclear plants and new GTG plants is shown by the LCOE estimates provided in Table 2-4, which were developed by the U.S. Energy Information Agency (EIA 2016).

Overnight Plant Capital Cost

The overnight plant capital cost includes all costs for engineering, procurement, and construction (EPC) of the nuclear plant. It does not include interest incurred during construction. Project activities included in the EPC cost estimate are as follows:

- Preconstruction and licensing activities, including site infrastructure development and preparation
- Reactor building and other on-site buildings

[18] As noted in a similar footnote in Section 2.4 for iPWR SMRs, it is expected that HTGR costs will be higher for the oil sands SAGD application because construction and labor costs are generally higher in the northern locations of Canada where there is limited skilled labor and construction seasons are shortened due to frigid weather during the winter months. However, costs would similarly be higher for other energy sources, including GTG, to which the HTGR costs are compared. Hence, these factors are not specifically accounted for in the cost estimates presented in this section.

- Reactor pressure vessel and internals
- Reactor cooling systems, refueling systems, and other associated systems and equipment,
- Power generation systems, including intermediate heat exchanger and turbine-generator system[19]
- Balance of plant systems and equipment such as used fuel storage and associated systems, radwaste systems, cooling towers, helium system, administration offices, security offices, radiological control access (RCA) entry, etc.
- Distributables costs such as construction services, field office and engineering services, home office and engineering services, temporary facilities, plant design costs, and plant startup costs

INL has developed and reported an estimate of the overnight EPC cost or total capital investment (TCI) for a NOAK single module 600 MW_{th} NGNP plant, which generates electricity via a Rankine or steam cycle, the same as the SC-HTGR. This estimate by cost category, in U.S. 2009 dollars, is provided in Table 3-2 (INL 2012). As reported by INL, this cost is based on a cost estimate developed for the pre-conceptual design of the NGNP and a top-down evaluation that used factored cost estimates for major equipment items and ratio factors based on industry experience and/or program guidance for balance of equipment costs, indirect costs, and project contingency. The level of project definition for the INL cost study was determined to be an Association for the Advancement of Cost Engineering (AACE) International Class 4 (feasibility study using factored or parametric models) estimate having an accuracy range of -30% to +50%. To allow for direct comparisons between estimates, this overnight EPC cost was escalated to 2014 U.S. dollars using the average CPI between 2009 and 2014 (10.3%), then converted to Canadian dollars using the average exchange rate in 2014 of 1.1 C$ per US$.[20] The overnight EPC cost for the single module plant (267 MWe) is estimated to range from US$4,190-8,970 /kWe (2014) or C$4600-9,870 /kWe (2014), with a best estimate of US$5,980 /kWe (2014) or C$6,580 /kWe (2014).

The authors are unaware of any publicly available information on the overnight EPC cost of the StarCore HTGR.

[19] While the principal focus of this study in on steam production, the cost of the turbine island is included so as to develop an LCOE that is on an equivalent basis with the CESAR study.
[20] It is recognized that the use of a single escalation factor for all of the cost categories is overly simplistic and not very accurate on an individual cost category basis. However, given the fairly large accuracy range of the cost estimate and that the escalation was only over a period of five years (10% escalation), it is judged that this approach is adequate for the purposes of the comparative analysis.

Table 3-2. Estimated Overnight EPC Cost for a Single Module (267 MWe) NGNP HTGR

EPC Cost Category	2009 US $millions	% of Total Cost
Preconstruction and Licensing	77	5
Reactor/Other Buildings	116	8
Reactor Vessel and Internals	200	14
Other Reactor Systems	109	8
Steam and Turbine-Generator	138	10
Balance of Plant and Equipment	141	10
Distributables	425	29
Other Costs	241	17
Total Overnight Cost	**1,448**	**100**

JAEA has reported an estimate of the overnight EPC cost for a NOAK single module GT-HTR300 HTGR having a capacity of 600 MW_{th} and 275 MW_e, which is similar in size to the NGNP and SC-HTGR plants. The cost estimate is for a plant that is designed to generate electricity using a direct Brayton cycle rather than with steam via a Rankine cycle. This estimate by cost category, in 2006 Yen, is provided in Table 3-3 (JAEA 2006). To allow for direct comparisons between estimates, this overnight EPC cost was first escalated to 2011 ¥ assuming an 8% escalation rate developed by JAEA (JAEA 2015), then escalated to 2014 U.S. dollars and 2014 Canadian dollars using the respective average CPI for each country between 2011 and 2014 (4.4% for Canada and 5.2% for U.S.), and lastly adjusted to account for a single unit plant[21] (a single module or unit is all that is needed for the reference SAGD application). The resultant overnight EPC cost for the single module plant (275 MWe) is US$3,420 /kWe (2014) or C$3,340 /kWe (2014).

Table 3-3. Estimated Overnight EPC Cost for a Single Module (275 MWe) GT-HTR300

EPC Cost Category	2006 ¥ millions	% of Total Cost
Reactor Vessel and Internals	11,400	21
Other Reactor Systems	5,700	10
Power Conversion System	14,000	26
Auxiliary Systems (e.g., HVAC, helium)	6,700	12
Electrical and Instrumentation System	5,800	11
Buildings	11,100	20
Total Overnight Cost	**54,700**	**100**

[21] The cost estimate in Table 3-3 is for a single unit in a four unit plant. The cost of a single unit in a single unit plant is 10% higher according to JAEA 2015.

Comparison of the two cost estimates shows that the overnight EPC cost estimate for the NGNP/SC-HTGR plant is about twice that for the similarly-sized GT-HTR300 plant. Since the two estimates were not reported using the same cost categories, it is not possible to identify where the two estimates are different and why. Specifically, the NGNP cost estimate separated out preconstruction and licensing activities and indirect costs for construction and engineer services, representing almost 35% of the total cost, whereas the GT-HTR300 cost estimate does not. Since neither estimate is based on a bottoms-up estimate of an advanced conceptual or detailed design having a detailed activity-based construction schedule, both estimates have significant uncertainty.

LCOE/LCOS

The LCOE includes the following:

- EPC overnight cost
- EPC (capital) financing costs, including debt financing (interest) and equity financing (return on investment) as applicable
- operations and maintenance (O&M) costs, which includes annual fixed costs (e.g., labor, regulatory fees, supplies and services, insurance) and variable costs (e.g., refueling outages, unplanned plant shutdowns/outages for repairs)
- nuclear fuel and used fuel management costs, which includes purchase of new fuel (e.g., uranium, uranium enrichment services, fuel fabrication) and storage and eventual disposition of used nuclear fuel (e.g., long term interim storage, permanent disposition/disposal of used fuel)
- taxes, which includes income and property taxes
- plant decommissioning costs
- owner costs, which includes for example human resource support and management, central office, plant licensing and permitting, annual regulatory inspections and oversight, legal fees, switchyard, project development, engineering services, contingency

INL has developed and reported a cost estimate for total EPC, annual M&O, annual nuclear fuel and disposition, and total decommissioning for a NOAK single module 600 MW_{th} NGNP plant that generates electricity via a Rankine or steam cycle, the same as the SC-HTGR (INL 2012). PNNL utilized this cost information to develop an LCOE for the reference SC-HTGR. In developing the LCOE, PNNL attempted to be consistent to the extent possible with the assumptions used in the development of the LCOE for the reference NuScale iPWR in order to allow direct comparisons. Key assumptions in the development of the LCOE were as follows: 1) 7.5% interest rate/rate of return on the capital investment, 2) plant capacity factor of 90%, 3) annual income/property tax rate of 34.6%, and 4) owner costs of 5.4 US$/MW-hr.[22] The resultant LCOE estimate by cost category, in U.S. 2009 dollars, is provided in Table 3-4.

Table 3-4. Estimated LCOE for a Single Module (267 MWe) NGNP/SC-HTGR

LCOE Cost Category	2009 US$ per MW-hr	% of Total LCOE
Capital (assumes 7.5% interest rate/rate of return)	55	48
O&M [assumes 165 full-time equivalent (FTE) staff]	18	16
Nuclear Fuel and Spent Fuel Disposition	16	14
Taxes (including income and property)	19	17
Owner Costs	5	5
Decommissioning	1	1
Total LCOE	114	100

To allow for direct comparisons between estimates, this LCOE was escalated to 2014 U.S. dollars using the average CPI between 2009 and 2014 (10.3%), then converted to Canadian dollars using the average exchange rate in 2014 of 1.1 C$ per US$. The LCOE for the single module plant (267 MWe), assuming an overnight EPC cost estimate accuracy range of -30% to +50% discussed above, is estimated to range from US$100-170 (2014) or C$110-180 (2014) [US$27-45/tonne steam (2014) or C$30-49/tonne steam (2014)], with a best estimate of US$130 /MW-hr (2014) or C$140 /MW-hr (2014) [US$34/tonne steam (2014) or C$37/tonne steam (2014)].

The authors are unaware of any publicly available estimate of the LCOE for the StarCore HTGR.

JAEA has developed and reported an estimate of the LCOE for a single module GT-HTR300 plant. This estimate by cost category, in 2006 Yen, is provided in Table 3-5 (JAEA 2006, JAEA 2015). Other than the limited estimating assumptions provided in this table, little information was provided on the assumptions used in the development of this estimate. To allow for direct comparisons between estimates, this LCOE was first escalated to 2011 ¥ assuming an escalation rate developed by JAEA for each cost category (JAEA 2015) and then escalated to 2014 U.S. dollars and 2014 Canadian dollars using the respective average CPI for each country between 2011 and 2014 (4.4% for Canada and 5.2% for U.S.). The resultant LCOE for the single module plant (275 MWe) is US$62 /MWe (2014) or C$61 /MWe (2014).[23] Note, there is insufficient information on the steam production rate for this HTGR design so an LCOS cannot be determined.

[22] While the INL capital costs include a category called “owner’s costs,” these are different than the owner’s costs described in this section. The INL “owner’s costs” are more similar to the “distributables” cost category defined for the reference iPWR LCOE estimate, and so are included in the capital cost portion of the LCOE for this analysis.

[23] The JAEA estimate included a new cost category in the updated 2011 LCOE estimate called “owner (policy measures)”. These are Japan-specific costs added after the Fukushima accident for disaster prevention, public relations, development of current/future technology for power generation, assessment and investigation of the accident, and others. These costs are not applicable to Canada and so are not included in the LCOE estimate.

Table 3-5. Estimated LCOE for a Single Module (275 MWe) GT-HTR300

LCOE Cost Category	2006 ¥ per kW-hr	% of Total LCOE
Capital (assumes discount rate of 3%)	1.26	46
O&M	1.11	21
Nuclear Fuel and Spent Fuel Disposition	1.46	12
Property Taxes	0.11	16
Owner Costs	Not Separately Provided	Not Separately Provided
Decommissioning	0.21	0.3
Total LCOE	**4.15**	**100**

As with the overnight EPC cost estimate discussed previously, comparison of the two cost estimates for the NGNP/SC-HTGR and the GT-HTR300 plants shows that the LCOE estimate for the NGNP/SC-HTGR plant is about twice that for the similarly-sized GT-HTR300 plant. It is interesting that the contribution of each cost category to the LCOE is about the same for both estimates (with the exception of course with Owner Costs since these were not included in the LCOE estimate for the GT-HTR300 plant). The major reason for the difference across all categories is due to the difference in the methodologies used to determine the LCOE. The estimate for the GT-HTR300 applies a discount rate of 3% to each category over a 40 year assumed plant lifetime, which is not the standard method for calculating LCOE. The NGNP/SC-HTGR, and the NuScale LCOE estimate discussed in Section 2.4, estimate LCOE using a customary or standard methodology.[24] Hence, the LCOE estimate for the GT-HTR300 plant cannot be directly compared to the LCOE estimate for the NGNP/SC-HTGR plant. For this study, the LCOE estimate for the NGNP/SC-HTGR will be used since the methodology used is a standard methodology that was also used to develop the reference iPWR (NuScale) LCOE estimate.

While limited information is available on the specific underlying basis-of-estimate for the LCOE breakdown provided in Table 3-4, the following observations, which are essentially the same as those made for the reference iPWR LCOE estimate, can be made about important cost drivers:

- Of the US$55 /MW-hr capital cost contribution, about 30% is for the overnight cost of $1.448 billion (2009 US$) and the remaining 70% is financing cost.

- Of the US$18 /MW-hr O&M cost contribution, about 45% is for the assumed staffing level of 165 FTE staff (discussed further in Section 3.5), about 13% is for utilities, support services, supplies, and plant upgrades, about 13% is for regulatory fees, about 11% is for the cost of

[24] A simple method for calculating the levelized cost of energy is to use a formula similar to the following: LCOE = {(overnight capital cost * capital recovery factor + fixed O&M cost)/(8760 * capacity factor)} + (fuel cost * heat rate) + variable O&M cost. This simple method is used in this study. See https://www.nrel.gov/analysis/tech-lcoe-documentation.html for more information.

periodic refueling and maintenance outages, and the remaining 18% is for annual capital improvements to the plant, taxes and insurance, and administration and general overhead.

- Of the US$16 /MW-hr new fuel and spent fuel disposition contribution, about 84% is for the purchase of new fuel and the remaining 16% is for spent fuel storage and disposition. It is unlikely that significant cost reductions are possible with this category because the cost of new nuclear fuel has been depressed the last few years, is likely to stay depressed for the foreseeable future, and is already a small contributor to the cost of nuclear power.

- The $19 /MW-hr for taxes will be a site specific assumption and, for this analysis, was assumed to be the same rate, about 35%, as that assumed in the reference iPWR LCOE analysis. This tax rate is consistent with the 39% tax rate assumed in the CESAR assessment of scenarios for reducing annual GHG emissions from oil sands production using SAGD (CESAR 2016).

Recently, X-energy LLC provided an estimate of the LCOE for their Xe-100 HTGR having capacity of 200 MW_{th} and 76 MW_e (X-energy 2017). The LCOE was estimated to be US$84 /MW-hr (2015), or C$107 /MW-hr (2015) [US$35.5/tonne steam (2015) or C$45.4/tonne steam (2015)] assuming an average exchange rate for 2015. No details underlying the analysis were provided.

From Section 3.3, for the reference oil sands SAGD facility application, just one SC-HTGR module is required. The LCOE estimates provided in this section do not need to be scaled for additional modules as was necessary for the reference iPWR (see Section 2.4).

3.5 HTGR Staffing Levels

As discussed previously, no nuclear power plants using HTGR SMR technology have yet completed construction, so no as-built/as-operated experience with these reactors are available. Hence, as with overnight EPC cost and LCOE, staffing levels developed by the reactor vendors are engineering estimates based on expected performance of the technology. Because of the inherent safety characteristics of these reactors, there is a reduced need for operations and maintenance staff for these types of reactors relative to current operating nuclear plants. Of the two reference HGTR SMRs evaluated in this report, only INL for the NGNP/SC-HTGR has publicly released an estimate of the number of FTEs needed to operate, maintain, and manage the plant after startup. The estimate is 166 FTEs for a single-module NGNP/SC-HTGR (INL 2012), a breakdown for which is provided in Figure 3-2. This estimate was developed by the reactor design supplier.

It is interesting to note that INL had estimated a staffing requirement of 382 FTEs for a single NGNP module using a methodology they developed for the NGNP project (INL 2012), a breakdown for which is also provided in Figure 3-2. The reactor design supplier estimated the much lower staffing level of 166 FTEs that was ultimately used in the INL study. INL was unable to reconcile the differences in their study, and had planned to address this in a later study. The NGNP project was cancelled before the staffing study could be completed. These differences, even within the same HTGR project, are reflective of the significant uncertainty in the expected staffing levels for advanced HTGRs, and is indicative of the need for actual operational experience with these reactors.

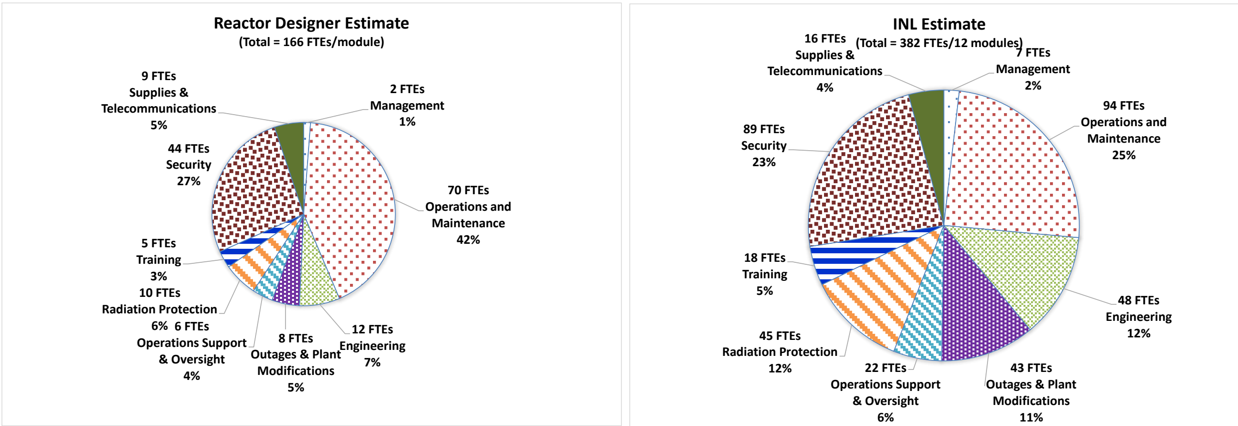

Figure 3-2. Estimated Number of FTEs for a NGNP/SC-HTGR Single-Module HTGR

The reduced staffing level estimate by the reactor design supplier is stated to account for advanced system automation, passive reactor safety systems, and reductions in security due to partially burying the core (GCRA 1994). Some specific bases provided by the vendor for their FTE estimate are as follows:

- High degree of automated control and information management
- Less prescriptive operational licensing requirements (e.g., technical specifications) based on 1) passive safety features, 2) long time intervals for operator response to upset conditions, and 3) use of highly automated information management and plant control systems (accomplishment of safety functions are embodied in the design) allowing:
  - Licensing focus on design verification and manufacture of the fuel and reactor modules
  - Substantially reduced regulatory effort applied to day-to-day operating site activities
- Simplified regulatory practices based on the principles of risk-based regulation, which aligns with CNSC licensing philosophy (see Section 4.2)
- Engineering and construction for plant modifications is considered a capital expense and therefore no FTEs are included for these activities
- Direct cycle power conversion system (Brayton cycle) [includes turbomachinery (gas turbine and generator), heat exchangers (recuperator, intercooler, and precooler), and ducts and seals that channel reactor coolant flow], which eliminates steam generation and condensing cycle (e.g. main circulator, steam generator, steam and feedwater systems, turbine-generators, and their auxiliary systems)

This last reason for the reduced staffing level does not apply to the reference SAGD facility application and so staffing levels my need to be somewhat higher to support steam generation. Also, these staffing estimates preceded enhanced nuclear security provisions at major nuclear facilities imposed by the CNSC in Canada and by the U.S. NRC in the U.S. following the September 11, 2001 terrorist attacks in the U.S., which resulted in increased security-related staffing at nuclear power plants.[25]

3.6 Comparison with Gas-fired OTSG Technology

CESAR estimated the LCOE for several scenarios postulated to reduce the annual GHG emissions from oil sands production using SAGD (CESAR 2016). The results shown in Figure 13 of the CESAR report show the LCOE for all of the scenarios to be about C$95/MW-hr (2014) in the 2020 time frame and decreasing to about C$80/MW-hr (2014) in the 2030 time frame,[26] which includes an assumed carbon or GHG price of C$30/tonne CO_2.

The LCOE for the reference HTGR plant (single module), as reported in Section 3.4, is estimated to be about C$140 /MWe (2014). Based on the capital cost estimate accuracy of -30%/+50% discussed in Section 3.4, the LCOE ranges from C$110 /MW-hr to C$180 /MW-hr (2014). The LCOE for the reference HTGR is about C$45 /MW-hr (range of C$15-85 /MW-hr) higher in the 2020 time frame, and increasing to about C$60/MW-hr (range of C$30-100 /MW-hr) higher in the 2030 time frame (assuming the cost of HTGR technology doesn't correspondingly decrease). Assuming no reductions or improvements in the cost of HTGRs, it is estimated that the price of natural gas would have to increase to C$10.5-11.0/GJ for HTGRs to become economically competitive with natural gas-fired OTSGs.

Figure 3-3 provides a "representative" breakdown of the LCOE cost for both HTGR and natural gas cogeneration.[27] The intent of this figure is to provide a relative comparison of the two technologies for the purpose of identifying the major reasons for the differences between the two. To develop this figure, component costs for natural gas cogeneration (CESAR 2016) and component costs for the SC-HTGR were used to develop the LCOE using the CESAR LCOE formula (CESAR 2016). Hence, the costs reported in this figure are somewhat different than those reported above. As with the similar discussion for iPWR technology discussed previously, the capital cost of an HTGR plant is significantly higher than that for cogeneration plants. The operating cost of an HTGR (excluding fuel) is also significantly higher than that for a cogeneration plant, however, this is somewhat offset by a higher fuel cost for the cogeneration plant.

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[25] See presentation by CNSC dated May 11, 2016 (http://www.nuclearsafety.gc.ca/eng/pdfs/Presentations/VP/2016/20160511-legal-authority-armed-eng.pdf).

[26] The CESAR study assumed the cost of natural gas to be 2014 C$3.25/GJ, and would hold steady from 2016 through 2030.

[27] The term "representative" is used to denote a single point estimate of the LCOEs for HTGR and natural gas cogeneration technologies using the same LCOE formula for both technologies. The ranges of LCOEs reported elsewhere in this report were generally developed in the respective references cited for these estimates, and escalated to a common year and/or converted to Canadian currency as necessary, and so reflect different assumptions in the LCOE estimates. The "representative" estimates were developed using common assumptions, such as the same LCOE formula, tax rate, discount rate, etc., based on available information. For this reason, the total LCOEs reported in Figure ES-3 for both HTGR and natural gas cogeneration are somewhat different (lower) than those developed from the cited references.

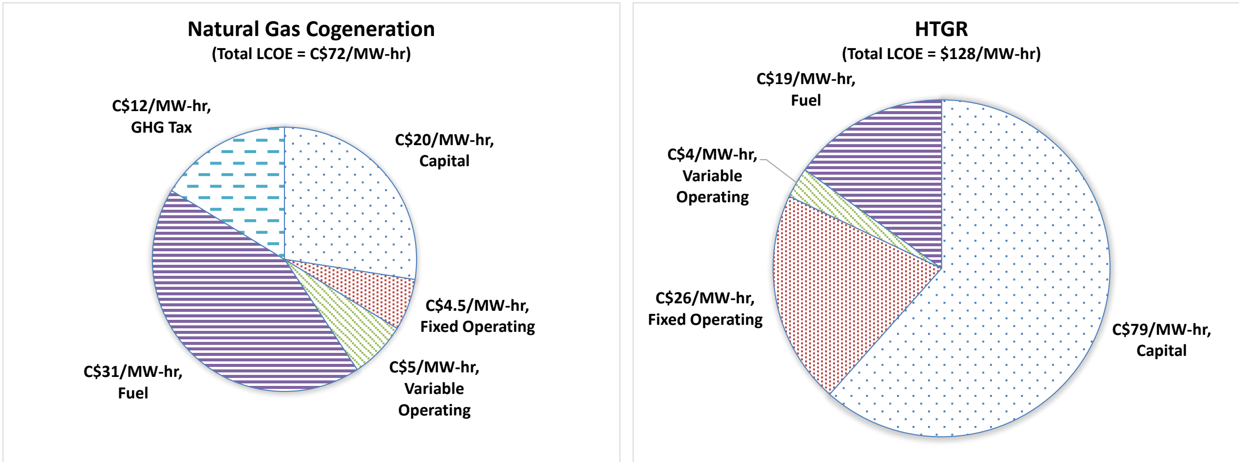

Figure 3-3. Comparison of Representative LCOE (2014) for HTGR and Natural Gas Cogeneration

3.7 Improving the Economic Competitiveness of HTGR Technology

Improving the economic competitiveness of HTGRs relative to GTG plants (surrogate for natural gas-fired OTSGs in this study) in providing the steam required for oil sands mining and extraction is a significant challenge with today's natural gas prices that are near historical lows. The following identifies potential opportunities to improve the economics of HTGRs (which are similar to those identified in Section 2.7 for iPWRs):

- Financing costs. The much lower LCOE for a GTG plant relative to an HTGR is largely due to the current low price of natural gas; the current Henry Hub spot price for natural gas is at or near historical lows. The cost of natural gas is the largest single contributor to the LCOE for modern GTG plants, while the largest single contributor to the LCOE for an HGTR is the initial capital investment to construct/commission the plant and associated cost of financing. The LCOE for an HTGR can be reduced by 30% or more by obtaining better financing conditions (i.e., reduced interest rate/return on investment to 3.5% or less from 7.5%).

  Reducing the construction schedule would also reduce financing costs incurred prior to plant operation. The LCOE for the reference (NGNP/SC-HTGR) HGTR assumed a construction schedule of about four years.

- Overnight EPC Costs. A breakdown of the overnight EPC cost for an HTGR plant is provided in Figure 3-4. There is significant uncertainty in the EPC cost of HTGR SMRs because HTGRs have not been deployed for commercial (electricity generation) application in almost 30 years (current operating HTGRs are research/demonstration reactors). If the EPC cost was reduced by 25%, the LCOE would decrease by about 15%.

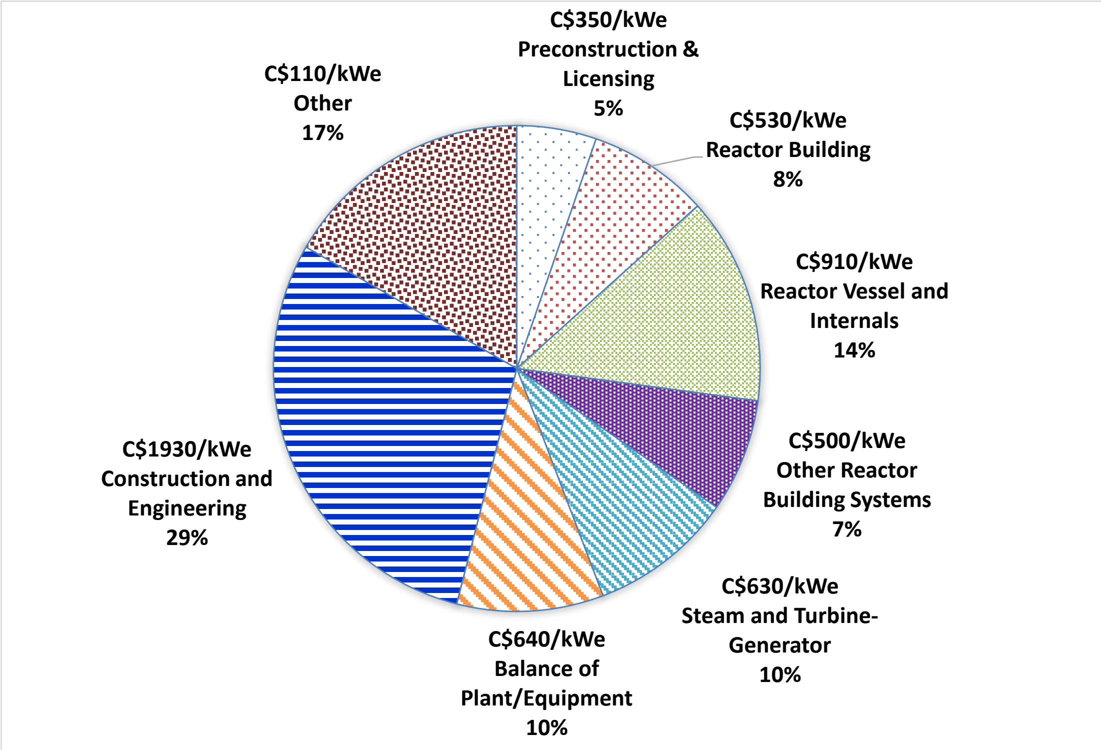

Figure 3-4. Overnight EPC Cost (2014) of an HTGR Plant (C$6600/kWe)

- Number of FTEs. O&M and security FTEs are estimated to contribute about 70% of the total plant operating staff estimate of 166 FTEs for the reference HTGR. While this staffing level is reduced from current generation PWR power plants due to credit for advanced passive/intrinsic safety/security features and automation of control and monitoring systems, it is still high relative to the staffing level of 50-60 FTEs required to operate a typical GTG plant. Staffing levels for HTGRs are, to some extent, driven by regulatory requirements to ensure safe/secure operation of the plant, and current generation PWR operating experience, which potentially could be reduced with a NOAK plant based on operational experience. If the staffing levels for a NOAK plant was 33-50% less than that of the FOAK plant, the LCOE would decrease by about 2-4%.

- Turbine Island. The cost of the reference HTGR is for a plant that utilizes all of the produced steam to generate electricity. However, the plant is mostly needed to generate steam. Hence, the turbine-generator plant is not needed, representing about 10% of the capital cost that could be substantially reduced. On the other hand, this reduced requirement is offset by the potential need for other equipment/systems (steam heaters or reboilers) to convert the superheated steam to saturated process steam having the appropriate pressure and temperature. If the overnight EPC cost of the turbine island is reduced by 80%, the LCOE would decrease by about 9%.

- Distributables (Temporary Buildings, Field Staff, Construction Equipment, etc.) are estimated to be about 29% of the overnight EPC cost of the reference HTGR plant. Since the oil sands SAGD facility is part of a large industrial facility, it may be possible to reduce the cost of distributables by sharing these costs with the SAGD and associated facilities. If the overnight EPC cost of distributables is reduced by 50%, the LCOE would decrease by about 10%.

4.0 Hydrogen Production for the Alberta Bitumen Upgrading Application

There are two principal methods used to extract bitumen from the Alberta oil sands: 1) surface mining of the oil sands followed by bitumen extraction and froth treatment and 2) in-situ recovery of the bitumen using processes such as steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). With either method, the resultant bitumen product may need to be upgraded to synthetic crude oil (SCO), which has the effect of reducing viscosity and increasing the hydrogen to carbon ratio thus enabling pipeline transportation without the need for diluent addition while increasing market value. This section of the report assesses the potential for using SMRs to produce the hydrogen (H_2) required for the bitumen upgrading process. The potential application of SMRs for surface mining of bitumen and for in-situ recovery of bitumen using SAGD were assessed in previous sections of this report.

For the purposes of this assessment, the reference bitumen upgrading facility is assumed to be sized to support upgrading of the bitumen product from the reference SAGD facility, which has a production rate of 200,000 barrels per day (bbl/d). The hydrogen consumption rate required to upgrade the bitumen is assumed to be 3.4 kg/bbl (Olateju 2016), which is equivalent to a hydrogen production rate of about 315 kNm^3/hr (thousand normal cubic meters per hour) for the reference upgrading facility. About one third of bitumen upgrading emissions are due to hydrogen production, predominantly from natural gas. While electricity is also consumed in the bitumen upgrading process, this study is limited to assessing the potential for SMR technology to generate the required hydrogen. Based on the hydrogen production requirement only, and considering other criteria, reference SMR technologies were selected. The economics of the reference SMR(s) were then evaluated and compared to the reference bitumen upgrading process, which is steam methane reforming (StMR).

However, since nuclear reactor technology is not currently used to produce hydrogen to any meaningful extent, this section also evaluates technology options for producing hydrogen using SMRs.

4.1 Technologies for Producing Hydrogen Using SMRs

Although abundant on earth as an element, hydrogen is almost always found as part of another compound, such as water (H_2O) and fossil fuels (e.g. natural gas), and must be separated from the compounds that contain it before it can be used. Hundreds of ways have been postulated for separating hydrogen from the large number of compounds to which it is attached. However, a comprehensive review of all of these methods is beyond the scope of this study. This study therefore relies heavily on previous studies that have evaluated a variety of methods for producing hydrogen with nuclear power to identify those that are most promising for efficient, cost-effective, large-scale production of hydrogen, and which are most actively being investigated today (GA 2000, Dominion Engineering 2009). These hydrogen production methods can generally be grouped into the following categories:

Steam reforming of fossil fuels (e.g., StMR) and other fossil fuel-based methods (e.g., coal gasification). StMR is the dominant process used to produce the hydrogen required for bitumen upgrading in the Alberta oil sands (Olateju 2016). In steam methane reforming, high temperature steam

(700°C-1000°C) is used to produce hydrogen from a methane source such as natural gas.[28] However, StMR is a fossil fuel (e.g., natural gas) intensive process resulting in GHG emissions ranging from 11,000-13,000 tonnes CO_2/tonne H_2 consumed (Olateju 2016). The reference SMR HTGRs evaluated in Section 3 of this report could potentially be used to produce the high temperature steam required for the StMR process. However, this application of SMR technology is not further considered in the study because of its substantial GHG emissions that would result from the continued use of natural gas for hydrogen production. This conclusion applies to the other fossil fuel-based methods for the same reasons. Per Section 1.1 of this report, reducing GHG emissions in the Alberta oil sands is the primary reason for considering potential applications of SMRs in the oil fields.

Direct thermolysis of water. Thermal decomposition, or thermolysis, is a process in which high temperature heat is used to chemically decompose water molecules into H_2 and oxygen (O_2). The direct thermolysis of water requires temperatures in excess of 2500°C for significant hydrogen generation and, even then, only 10% of the water is decomposed, with the remaining 90% being recycled (GA 2000). No SMRs are currently being designed to produce process heat at this temperature and so this method is no longer considered in this study.

Electrochemical water-splitting processes or water electrolysis. In this process H_2 is produced from electrolysis by passing a direct electric current with the aid of an electrolyte through water to decompose the water molecules into H_2 and O_2. Water electrolysis is a water-splitting process since no chemicals are consumed during the reaction. This process is similar to direct thermolysis of water except the water decomposition is accomplished at much lower temperatures. There are two principal processes that are actively being evaluated:

- Low temperature electrolysis (LTE). LTE decomposes water into its basic elements at standard temperature and pressure. It is a fairly common method for producing H_2 today, but generally in small quantities for specialized uses requiring high purity hydrogen.[29] Since LTE only requires electricity and water to produce hydrogen, any of the SMR technologies evaluated in this study and in the Phase I report can be used, and so is further considered below.

- High temperature steam electrolysis (HTSE). This process is similar to LTE except that it achieves a higher efficiency by operating at higher temperatures. Specifically, high temperature steam up to 950°C, rather than liquid water as in LTE, is decomposed. The HTSE process has been the focus of much consideration for the production of H_2 using nuclear energy, and was specifically down-selected by the US DOE for further research and development (R&D) (Dominion Engineering 2009). Furthermore, the HTSE process was selected as the preferred process for further development by the DOE for integration with the NGNP, which is an HTGR. This water-splitting process continues to actively be investigated for use with HTGRs, because of its ability to generate high temperature steam, and so is further evaluated in this study.

[28] From U.S. Department of Energy (DOE) website: https://energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming.
[29] See http://www.fsec.ucf.edu/en/consumer/hydrogen/basics/production-electrolysis.htm.

Thermochemical water-splitting processes. Thermochemical water splitting uses high temperature heat (750°C – 1000°C) and chemical reactions to produce H_2 and O_2 from water. Thermochemical water-splitting processes have been studied extensively with dozens of cycles proposed (GA 2000). The processes or cycles given most attention over the years are considered water-splitting processes since all process chemicals are fully recycled. One variant of this process, the Sulfur-Iodine (SI) process, was specifically down-selected by the DOE for further R&D (Dominion Engineering 2009), and has been the subject of extensive R&D in Japan for integration with HTGRs to produce H_2 [see the Phase I report (PNNL 2016), Section 5.1, GT-HTR300 HTGR for further information]. This water-splitting process continues to be actively investigated for use with HTGRs, because of its ability to generate the high temperature heat, and so is further evaluated in this study.

Hybrid water-splitting processes. Hybrid water splitting processes include both chemical reactions and electrolysis to produce H_2 and O_2 from water, hence both high temperature heat (750°C – 1000°C) and electricity are required. One specific variant of this process, the Hybrid Sulfur-Iodine (HyS) process, was specifically down-selected by the DOE for further R&D (Dominion Engineering 2009). For this reason, it is further evaluated in this study even though it is not being as actively investigated as the other water-splitting processes previously discussed.

Other processes. There are numerous other hydrogen production technologies that have been identified and, in some cases, are actively being investigated, such as biomass gasification, biomass fermentation, photoelectrochemical water splitting, photobiological water splitting, etc.[30] None of these however are being actively investigated for application with nuclear power and so are no longer considered in this study.

4.2 Low Temperature Electrolysis (LTE)

LTE has historically been perceived as electricity-intensive and not very efficient because of the energy required to split water molecules. However, recent advancements in electrolyzer technologies have improved the cost effectiveness of LTE. Two basic commercial methods are used in LTE: alkaline electrolyzers and proton exchange membrane (PEM) electrolyzers (INL 2009).

There are two basic types of alkaline electrolyzers. The tank type, or unipolar, electrolyzer is an anode and a cathode immersed in a tank filled with a solution of electrolyte, usually potassium hydroxide, in pure water which, when the electrodes are connected to an electrical power source, causes the water to separate into H_2 and O_2. In the bipolar, or filter-press, alkaline electrolyzer the electrolyte and water flows into alternating layers of electrodes and separation diaphragms that are clamped together (INL 2009). In a PEM electrolyzer, the water flows into the anode that is separated from the cathode by an ion-conducting solid polymer electrolyte membrane that allows H_2 ions to pass through. Figure 4-1 provides a schematic of a PEM electrolyzer (Strategic Analysis 2013).

[30] See, for example, https://www.afdc.energy.gov/fuels/hydrogen_production.html.

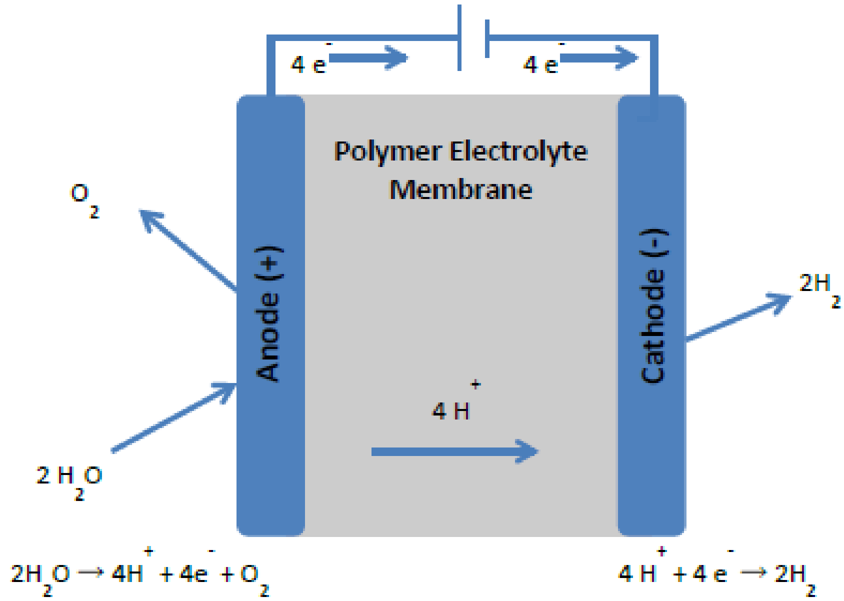

Figure 4-1. Schematic of a PEM Elecrolyzer

Both electrolyzer designs for hydrogen production systems would typically include a water source, water purification systems, electrical power supply, hydrogen gas dryer, hydrogen gas purifier, hydrogen gas compressor, and hydrogen storage tanks. Other equipment typically required would be a nitrogen system for purging piping and components, chilled water for cooling, an oxygen collection system (if desired), and instrument air for controls.

For this study, iPWR technology was selected as the reference SMR technology for integration with LTE technology to produce hydrogen. This selection was based on the same considerations as discussed in Section 2.1, and because electricity is the only energy source required for LTE technology to perform its function (e.g., high pressure steam is not required).

An estimate of the levelized cost of hydrogen production using iPWR technology was developed using the following assumptions:

- The LCOE estimates for iPWR technology from Section 2.4, which represents the full cost of producing the electricity required by the LTE plant. For the NuScale iPWR, the LCOE was estimated to be US$114/MW-hr (2014) or C$125/MW-hr (2014) for a 12-module or larger plant.

- Use of alkaline electrolyzers with the following performance characteristics: hydrogen production rate of 300 – 485 Nm^3/hr per electrolyzer and 2.328 MWe per electrolyzer, (Olateju 2016).[31]

- Electrolyzer levelized cost of hydrogen production ($LCOH_2$) for a central water electrolysis plant, which is based on a plant having a design capacity of 52,300 kgH_2/day. Specifically, capital cost

[31] The reference electrolyzer used for this study was the Norsk Hydro Atmospheric Type No. 5040 from Table 2.4 of Olateju 2016.

– US$0.6/kg$H_2$, fixed O&M cost – US$0.2/kgH_2, and variable O&M cost – US$0.1/kg$H_2$ (2007) (USDOE 2015).

- 2007 U.S. dollars were escalated to 2014 U.S. dollars using the average CPI between 2009 and 2014 (14.2%), then U.S. dollars were converted to Canadian dollars using an average 2014 exchange rate of 1.1 Canadian dollars per U.S. dollar.[32]

Based on these assumptions, the electrical generation capacity required to support the H_2 production requirement is estimated to be 1510 to 2450 MWe, depending on the efficiency of the electrolysis process. The resultant number of iPWR modules needed to provide this electrical energy requirement ranges from 34 to 55 NuScale iPWR modules or 15 to 25 SMART iPWR modules. Deployment of these large numbers of modules for the bitumen upgrading application is not feasible or cost effective and so is not considered further in this report. However, research is continuously improving the efficiency, or reducing the electricity usage, of electrolyzers. Based on this, it is recommended that improvements in LTE technology be reconsidered should use of SMR technology for hydrogen production be pursued.

4.3 High Temperature Steam Electrolysis (HTSE)

The HTSE electrolysis water-splitting process utilizes a solid-oxide electrolysis cell (SOEC) to produce H_2. An SOEC is a solid-state electrochemical device consisting of an oxygen-ion-conducting electrolyte, such as yttria-zirconia (YSZ) or scandia-stabilized zirconia (ScSZ), with porous electrically conducting electrodes deposited on either side of the electrolyte. A cross-section of an SOEC design is shown in Figure 4-2 (INL 2010). The design shown has a nickel cermet[33] cathode and a perovskite anode, such as strontium-doped lanthanum manganite (LSM). The flow fields conduct electrical current through the stack and provide flow passages for the process H_2 and O_2 streams. A separator plate or bipolar plate separates these streams and must be electrically conducting, so it is usually a metallic material such as a ferritic stainless steel.

As shown in the figure, a mixture of mostly steam (about 90%) and H_2 (about 10%), at a temperature of 650-950°C, is supplied to the cathode side of the electrolyte. The exiting stream is a mixture of mostly H_2 (about 90%) and water (about 10%). The water is not fully utilized in the process to improve the efficiency of the SOEC. The H_2 and residual steam streams are passed through a condenser or membrane separator to purify the hydrogen. Tests of solid ceramic membrane electrolyzers have been shown to achieve higher efficiencies than PEM or alkaline electrolyzers when operated at very high temperatures (INL 2010).

[32] It is recognized that the use of a single escalation factor for all of the cost categories is overly simplistic and not very accurate on an individual cost category basis. However, on an aggregate overnight cost basis this approach is judged to provide a reasonable approximation that is accurate to within a few percent of what the result would be with a more detailed analysis.
[33] Cermet is a composite material composed of ceramic and metallic materials.

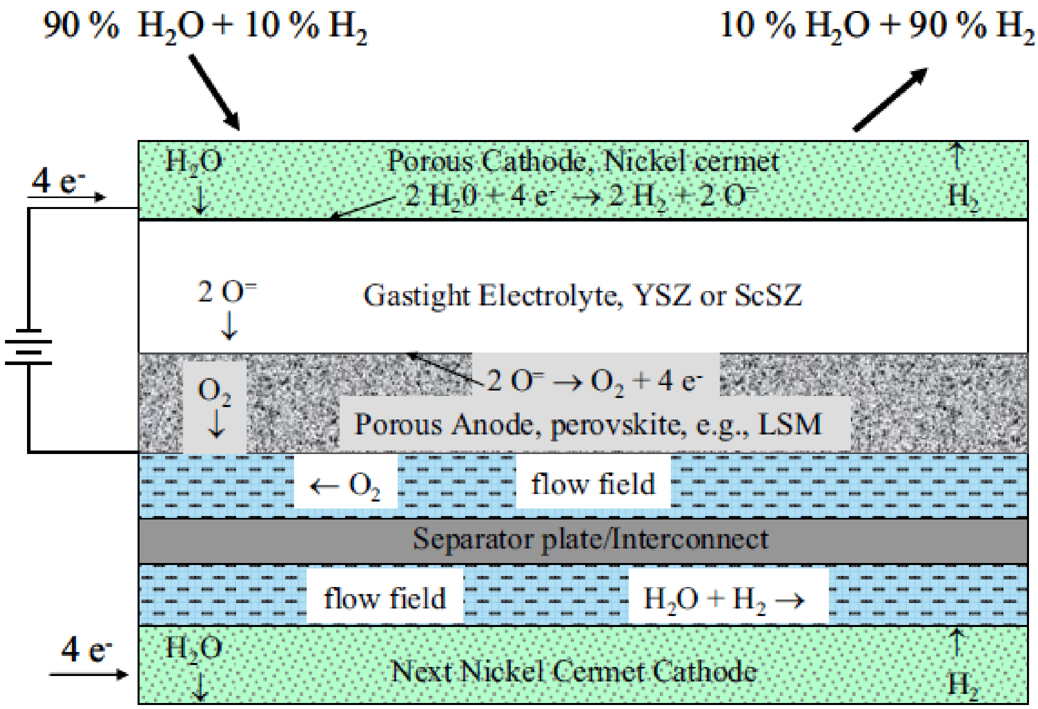

Figure 4-2. Cross-section of an SOEC Stack

For this study, HTGR technology was selected as the reference SMR technology for integration with HTSE technology to produce hydrogen. This selection was based on the same considerations as discussed in Section 3.1, and because iPWR technology does not operate at a sufficiently high temperature to produce the high temperature steam required for the HTSE process.

H_2 production with the HTSE process is most efficient at very high temperatures, with efficiencies greater than 55% achieved for temperatures greater than about 850°C (INL 2010). However, HTGRs that are expected to be commercially deployable before 2030 are expected to only have operating temperatures of about 750°C. Significant research remains to demonstrate performance of materials to be used in Very High Temperature Gas Reactors (VHTGRs) having operating temperatures greater than 850°C, which are not expected to be commercially deployable until after 2030. However, because the HTSE process has been demonstrated to maintain reasonably good efficiency at operating temperatures of 750°C and even lower (efficiencies greater than 40%), this water-splitting process is the technology of choice for further research and development by the DOE. Lower temperature HTGRs in combination with the HTSE water-splitting process is expected to be deployable before 2030.

An estimate of the levelized cost of H_2 production using HTGR technology was developed using the following assumptions:

- The LCOE was estimated for the reference SC-HTGR discussed in Section 2 using estimated capital costs for a Brayton cycle for electricity production rather than the Rankine Cycle for steam production developed in Section 2.4 (INL 2012). This LCOE represents the full cost of producing the electricity and high temperature steam required by the HTSE plant. The LCOE was estimated to be US$125/MW-hr (2014) or C$138/MW-hr (2014) for a single-module plant.

- Use of SOECs with the following performance characteristics: electrical energy requirement of 35.1 to 36.8 kWe-hr/kgH_2, thermal energy requirement of 11.5 to 14.1 kWth-hr/kgH_2, H_2 production rate of 50,000 kgH_2/d per SOEC, and SOEC efficiency of 66 to 72% (USDOE 2016).

- SOEC levelized cost of hydrogen production (LCOH_2) for a central SOEC plant, which is based on a plant having a design capacity of 50,000 kgH_2/day. Specifically, stack capital cost – US$0.24/kg$H_2$, balance-of-plant (BOP) capital cost – US$0.45/kg$H_2$, initial capital cost and replacement cost – US$1.00/kg$H_2$, fixed O&M cost – US$0.38/kgH_2, and variable O&M cost – US$0.01/kg$H_2$ (2007) (USDOE 2016).

- 2007 U.S. dollars were escalated to 2014 U.S. dollars using the average CPI between 2007 and 2014 (14.2%), then U.S. dollars were converted to Canadian dollars using an average 2014 exchange rate of 1.1 Canadian dollars per U.S. dollar.

Based on these assumptions, the electrical generation capacity and additional thermal energy capacity required to support the hydrogen production requirement is estimated to be 1000 to 1040 MW_e and 330 to 400 MW_{th}, respectively. It is estimated that about four SC-HTGR modules are needed to provide these electrical and thermal energy requirements. The LCOH_2 is estimated to range from C$6.4-6.9/kg$H_2$ (2014).

For comparison, a cost estimate for H_2 production in Canada using an HTGR plant of similar size to the SC-HTGR plant used in this study reports a cost of C$4.3/kg$H_2$ (2014) (El-Emam 2015). The main reason for the difference appears to be due to the assumed capital cost of C$2,100 million for the HTGR plant, which is based on cost information by the International Atomic Energy Agency (IAEA), whereas this study assumes a cost of C$5,585 million, a factor of 2.7 higher. In a separate study by INL, a hydrogen production cost of about C$4.0 (2014) is estimated using essentially the same HTGR plant assumed in this study. In this case, the capital costs assumed for the HTGR and hydrogen plants for the two studies are very similar (C$3.14/kg$H_2$ in this study and C$2.91/kg$H_2$ in the INL study). However, operations and maintenance costs, and variable costs such as fuel, are estimated to be C$1.92/kg$H_2$ in this study and C$1.05 in the INL study. The reason for this difference is unclear. Also, other costs are estimated to be C$1.27/kg$H_2$ in this study, and C$0.18/kg$H_2$ in the INL study. The principal reason for this difference appears to be that the INL study did not include costs for income and property taxes or owner costs.

In comparison, the cost of hydrogen production using natural gas StMR is estimated to be C$1.87/kg$H_2$ (2014) (Olateju 2016), which assumes a natural gas price of C$5/GJ. However, the StMR H_2 cost does not account for the price of carbon that would be applied to the CO_2 emitted during StMR production of H_2. As discussed in Sections 1.6 and 2.6, the CESAR study assumes a carbon price of C$30/tonneMT CO_2 in 2017 and 2018, and increasing by 2% per year after 2018 (CESAR 2016). If a carbon price of C$30/tonne CO_2 were applied to the CO_2 emissions by the reference StMR H_2 plant in the oil sands bitumen upgrading application, the unit cost of the H_2 production would increase by C$0.33/kg$H_2$ to C$0.39/kg$H_2$, assuming 11-13kg CO_2/kgH_2 emissions from natural gas StMR (Olateju 2016). The cost of

H_2 production using natural gas StMR is estimated to range from C$2.2-2.3/kg$H_2$ (2014) after accounting for the price of carbon emissions. On this basis, the cost of SC-HTGR/HTSE technology is estimated to be higher than natural gas cogeneration by C$4.1-4.7/kg$H_2$ (2014), or a factor of 3 to 3.5 higher.

4.4 Sulfur-Iodine (SI) Process

The SI process is a thermochemical process that includes (1) decomposition of hydrogen iodide (HI) at temperatures up to 450°C in the presence of a carbon catalyst to yield hydrogen and iodine (I_2), (2) recycle of the iodine in a column reactor where it reacts exothermically at about 120°C with sulfur dioxide (SO_2) to form hydriodic acid and sulfuric acid (H_2SO_4), (3) gravimetric separation of the HI and H_2SO_4, and (4) thermal/catalytic decomposition of H_2SO_4 to oxygen and SO_2 at high temperature, up to 900°C, with the SO_2 recycled back for reaction with I_2 (Dominion Engineering 2009). In the SI process, H_2SO_4 acts as oxygen carrier and HI as a hydrogen carrier. Figure 4-3 provides an overview of the SI process and its three primary chemical reactions (Dominion Engineering 2009).

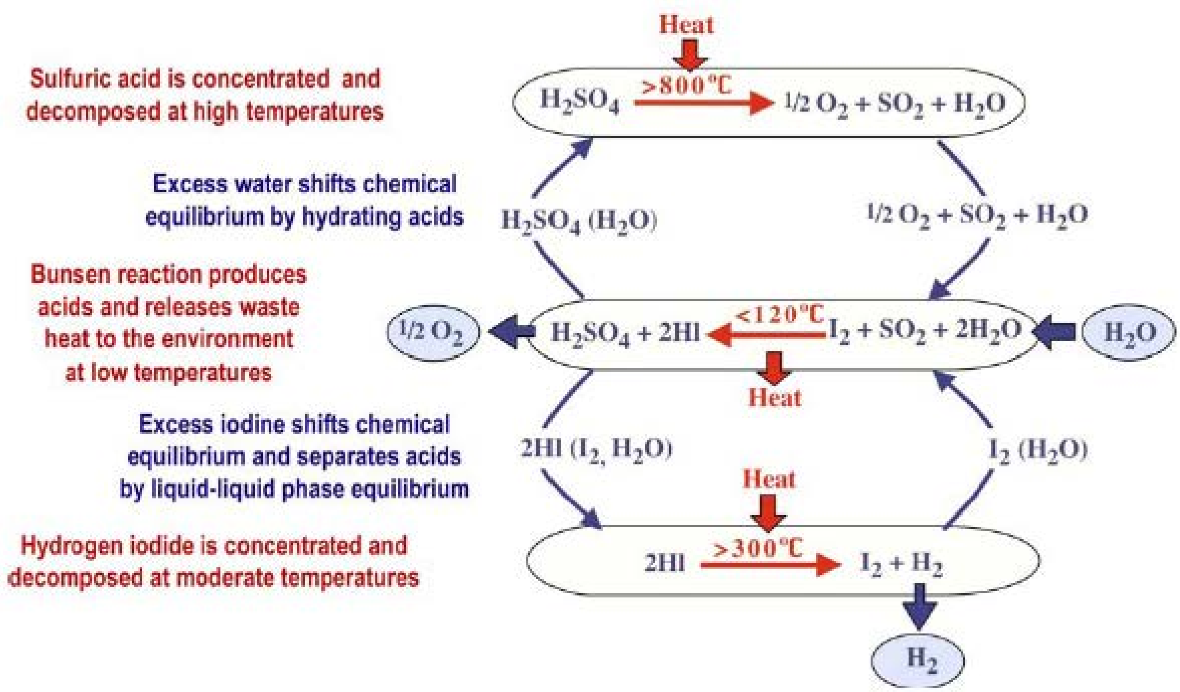

Figure 4-3. Overview of the SI Process and Its Three Primary Chemical Reactions

The efficiency of this process has been demonstrated to be greater than 50% for temperatures greater than 900°C. However, the efficiency drops off quickly with decreasing temperature, dropping below 40% at a temperature of 800°C (INL 2010). Because the SI process requires temperatures greater than 800°C for efficient decomposition of the sulfuric acid, VHTGR type reactors are necessary to integrate/couple with this process. The Japan HTGR development program is intended to demonstrate HTGRs that operate at temperatures of 850-950°C and are coupled to an SI process for H_2 production. Because HTGRs operating at these temperatures are not expected to be deployable by 2030, the SI water-splitting process is not further considered in this study.

While not being as actively investigated as other water-splitting processes, it is further considered in this study because of its potential to produce hydrogen at a lower cost than the SI process. However, because this technology does not appear to be under active development, and because of the lack of data on the cost of this technology, the hydrogen production cost of the SI process integrated with an SMR was not further evaluated in this study.

4.5 Hybrid Sulfur (HyS) Process

The HyS process is a relatively simple water-splitting process that involves a single electrochemical step and a single thermochemical step, hence both high temperature heat (750°C – 1000°C) and electricity are required. The process produces H_2 and O_2 in a polymer membrane based electrolysis cell operating at temperatures below 125°C. Sulfur dioxide is used to depolarize the cell and allow it to operate at lower voltages and hence higher efficiencies and current densities as compared to higher temperature electrolysis cells. Sulfuric acid is produced along with H_2 in the cells. As with the SI process, the H_2SO_4 is recycled by thermal/catalytic decomposition to O_2 and SO_2 at high temperature, up to 900°C, with the SO_2 recycled back for reaction with water (Dominion Engineering 2009). Figure 4-4 provides an overview of the HyS process and its two chemical reactions (INL 2008). While not being as actively investigated as other water-splitting processes, it is considered in this study because of its potential to produce hydrogen at a lower cost than the SI process. However, because this technology does not appear to be under active development, and because of the lack of data on the cost of this technology, the hydrogen production cost of the HyS process integrated with an SMR was not further evaluated in this study.

$SO_2 + 2\ H_2O \rightarrow H_2 + H_2SO4$ (electrochemical, 80°C –120°C)

$H_2SO4 \rightarrow H_2O + SO_2 + \frac{1}{2}O_2$ (thermochemical, 800°C –900°C)

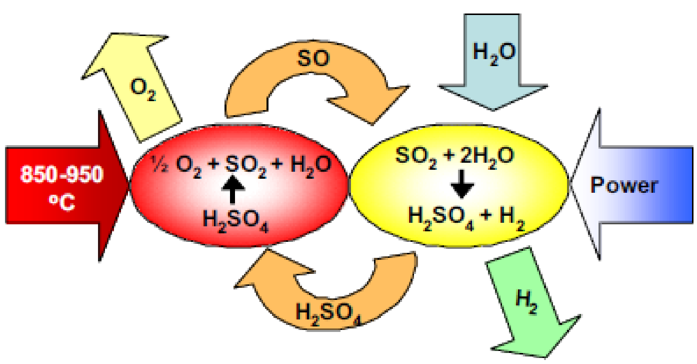

Figure 4-4. Overview of the HyS Process and Its Two Chemical Reactions

5.0 Challenges in the Application of SMRs in the Alberta Oil Sands

This section addresses several challenges with deploying SMRs in the oil sands applications evaluated in this report. These include 1) the number of staff and the expertise of this staff required to operate and maintain SMRs, 2) the regulatory approval timeline for licensing SMRs for the oil sands application, 3) technical and logistical challenges of shipping very large components to the oil fields in Alberta, 4) management of used nuclear fuel and radioactive wastes generated during operation and decommissioning of SMRs, and 5) nuclear supply chain difficulties. Each of these challenges is discussed briefly in this section.

5.1 Human Capital and Labor Expertise Requirements

No nuclear power plants using any of the SMR technologies evaluated in the Phase I report (PNNL 2016), or further evaluated in this study, have yet been constructed or operated. Hence, as with the overnight EPC cost and LCOE estimates discussed previously, staffing levels developed by the reactor vendors are engineering estimates based on expected performance of these evolutionary SMR technologies. The extensive use of inherent and passive safety features in SMRs is expected to substantially reduce, relative to current generation nuclear power plants, the number of full-time staff needed to safety operate and maintain these SMRs. In fact, some vendors of particularly small SMRs with long-life reactor cores (e.g., StarCore) are claiming that very few full-time staff will be needed at the plant site, and that semi-remote operation may even be possible. These claims remain to be demonstrated.

As discussed in previous sections of this report, of the four reference iPWR and HTGR designs evaluated in this study, estimated staffing levels are publicly available for two of them, NuScale and SC-HTGR, while a breakdown by skill type is only available for the SC-HTGR. PNNL developed a skill type breakdown of the FTE estimate for the NuScale iPWR based on PWR operating experience and engineering judgement. The total full time equivalent (FTE) staffing level for a 12-module NuScale plant (1920 MW_e) and for a single-module SC-HTGR plant (625 MW_{th}) are estimated to be 360 FTEs and 166 FTEs, respectively. A comparison of the number of FTEs by labor category is provided in Figure 5-1. Both estimates assume five-shift, around-the-clock operation of the plant. It is estimated that O&M (including nuclear operators), security, and radiological protection staff compose about 60% of the FTEs for the NuScale plant and almost 75% of the FTEs for the SC-HTGR plant. Many of these staff require specialized training and skills that are unique to nuclear plant operation. Both the number of required staff and the specialized skill/training required by many of these staff may pose a challenge to the oil sands operations due to the remoteness of these facilities. SMR vendors are pursuing means with national regulators to reduce staffing requirements, including putting the reactor underground (enhanced security), automating operations (reduced M&O staffing), refueling the reactor offsite (at the vendor facilities), and demonstrating operational effectiveness through experience with the first deployed units.

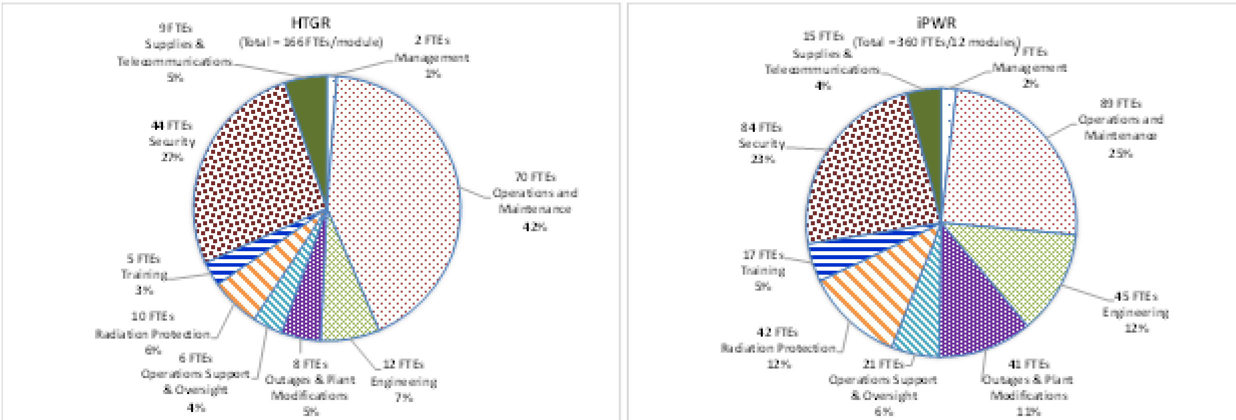

Figure 5-1. Estimated Number of FTEs by Skill Type for HTGR and iPWR

5.2 Canadian Nuclear Regulatory Paradigm

The Canadian Nuclear Safety Commission (CNSC) regulates the use of nuclear energy and nuclear materials in Canada to protect health, safety, security and the environment. The CNSC's regulatory framework consists of laws passed by the Canadian Parliament that govern the regulation of Canada's nuclear industry, and regulations, licenses, and documents that the CNSC uses to regulate the industry.[34] The CNSC currently regulates the operation of four nuclear power plants, having 17 operating nuclear power reactors of the CANDU type, and several research reactors. While no SMR reactors, as defined in the Phase I report (PNNL 2016), or advanced reactors have been licensed to-date by CNSC, several SMR designs are currently undergoing review, or have applied to be reviewed, under CNSC's pre-licensing Vendor Design Review (VDR) process.

CNSC guidance document GD-385 (CNSC 2012) describes the VDR process and is the source for the summary-level information presented in this section on the VDR process. An important clarification regarding the pre-licensing VDR process is that it is an optional service offered by the CNSC, it is not a review that results in certification of the reactor design or issuance of a CNSC license, and it is not a prerequisite to licensing. Rather, the primary purpose of a VDR is to inform the reactor technology vendor of the overall acceptability of the reactor design by providing for early identification and resolution of potential regulatory or technical issues in the design process, particularly those that could result in significant changes to the design or nuclear safety case. Hence, the process should not be triggered by the reactor technology vendor unless the vendor's conceptual design is essentially complete and the basic engineering program has begun (i.e., design requirements are being established) (CNSC 2016). The conclusions of a VDR do not bind or otherwise influence decisions made by the CNSC, with whom the authority resides to issue licenses for nuclear power plants and SMRs. However, it is expected that the outcomes of the process helps the reactor technology vendor in discussions with potential future licensees who would apply for a CNSC license to construct and operate an SMR utilizing their technology.

[34] For additional information about CNSC's regulatory framework, go to https://www.cnsc-ccsn.gc.ca/eng/acts-and-regulations/regulatory-framework/index.cfm.

The vendor design review is divided into three phases, each requiring increasingly more detailed technical information:

- Phase 1 review – Compliance with regulatory requirements: CNSC staff assess the information submitted in support of the vendor's design and determine if, at a general level, the design intent complies with CNSC design requirements (see further discussion below), and related regulatory requirements. This phase takes about one year and 5,000 hours of CNSC staff time to complete (CNSC 2016).

- Phase 2 review – Pre-licensing assessment: In this phase the CNSC review goes into further detail, with a focus on identifying potential fundamental barriers to the licensing of the vendor's design for a nuclear power plant or small reactor in Canada. This phase takes 18 months to two years and 10,000 hours of CNSE staff time to complete (CNSC 2016).

- Phase 3 review – Pre-construction follow-up: In this phase, the vendor can choose to follow up on one or more focus areas covered in Phase 1 and 2 against CNSC requirements pertaining to a license to construct. For those areas, the vendor's anticipated goal is to avoid a detailed revisit by CNSC during the review of the construction license application.

Phase 1 and 2 reviews have 19 review focus areas, representing key areas of importance for a future construction license. The Phase 3 review is tailored on a case-by-case basis.

The SMRs and advanced reactors that are being reviewed or have applied to be reviewed within the pre-licensing VDR process are identified in Table 5-1, which also provides a brief summary of the reactor type, electrical capacity, and status of the VDR process for each (CNSC 2017). As Table 5-1 shows, the only reference SMR evaluated in this study for which the VDR process has been initiated is the StarCore HTGR.

As stated earlier, the VDR process is not a license review and so does not result in the issuance of a license by the CNSC. The design and safety of a SMR will still require review by CNSC if the SMR technology is proposed in an application for a CNSC license to construct and operate an SMR. Completing all phases of the VDR process may accelerate the license review process, but it does not replace it.

The licensing process for a SMR in Canada must follow the CNSC licensing process for any new nuclear reactor in Canada (CNSC 2008a). In the CNSC’s regulations, separate licenses are required for each of the five phases in the lifecycle of a nuclear power plant:

1. a license to prepare a site;

2. a license to construct;

3. a license to operate;

4. a license to decommission; and

5. a license to abandon.

Table 5-1. Status of Pre-licensing Vendor Design Reviews

Vendor	Name of Design/ Cooling Type	Electrical Capacity (MWe)	Phase Applied for	Review Start Date	Status
Terrestrial Energy Inc.	IMSR Molten Salt	200	Phase 1	April 2016	Phase 1 Complete
Ultra Safe Nuclear Corporation	MMR-5 & MMR-10 HTGR	5-10	Phase 1	December 2016	Assessment in Progress
LeadCold Nuclear Inc.	SEALER Molten Lead	3	Phase 1	January 2017	Assessment in Progress
Advanced Reactor Concepts, Ltd.	ACR-100 Liquid Sodium	100	Phase 1	Fall 2017	Assessment in Progress
URENCO	U-Battery HTGR	4	Phase 1	Tentative Fall 2017	Service Agreement Under Development
Moltex Energy	Stable Salt Reactor Molten Salt	300	Series Phase 1 and 2	Tentative Fall 2017	Service Agreement Under Development
StarCore Nuclear	StarCore Module HTGR	10	Series Phase 1 and 2	To Be Determined	Service Agreement Under Development

However, the applications to prepare a site, to construct, and to operate a new nuclear power plant may be assessed in parallel. In addition to the five licensing stages, an environmental assessment (EA) must be carried out, so as to identify whether a project is likely to cause significant adverse environmental effects, before a license can be issued by CNSC. The EA is generally conducted in parallel with the preparation of a license to prepare a site. The licensing process for each phase involves significant public involvement, including by Aboriginal groups. Figure 5-2 provides an overview of the CNSC licensing process that is applicable to each phase (CNSC 2016).

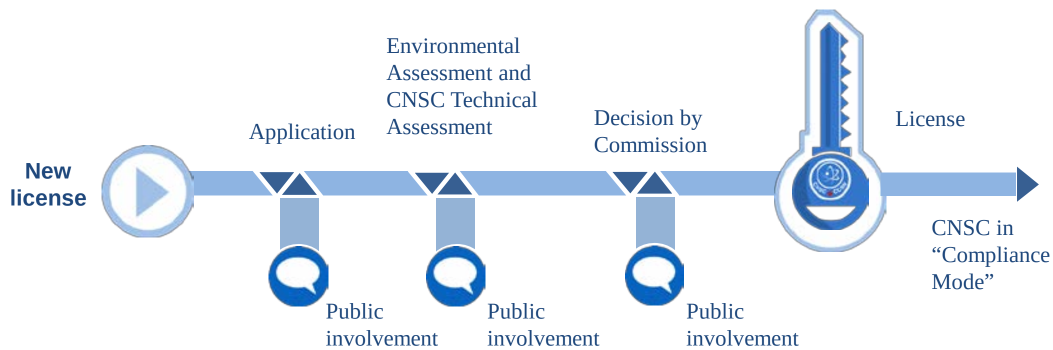

Figure 5-2. CNSC Licensing Process Overview

Figure 5-3 provides an approximate timeline for completing the licensing process for a new nuclear power plant or a new large SMR from the time of submission of an application to prepare a site through receiving a license from the CNSC to operate the plant, which includes time for the licensee to construct the plant (CNSC 2008a, CNSC 2015). As shown in Figure 5-3, the CNSC estimates that the total time from the receipt of an application to the issuance of a license to operate is approximately nine years, taking into consideration that a number of activities may proceed in parallel. CNSC estimates that this total time could potentially be reduced to approximately six to seven years for a very small SMR (CNSC 2015). Very small SMRs are defined by CNSC as having electrical capacities in the range of 5 to 35 MW_e (CNSC 2016). CNSC defines an SMR as having a thermal capacity of about 200 MW_{th} or less (CNSC 2011a). By these definitions, the following observations can be made:

- The StarCore SMR (28 MW_{th}, 14 MW_e) evaluated in this study as a reference HTGR would be classified as a very small SMR. The total time from the receipt of an application to the issuance of a license to operate could be approximately six to seven years.

- The NuScale SMR (160 MW_{th}, 47.5 MW_e) evaluated in this study as a reference iPWR would be classified as a small/moderate-size SMR. The total time from the receipt of an application to the issuance of a license to operate would presumably be between seven and nine years.

- The SMART SMR (330 MW_{th}, 100 MW_e) and SC-HTGR SMR (625 MWth, 272 MWe) that were evaluated as a reference iPWR and a reference HTGR, respectively, would presumably be classified as large SMRs. The total time from the receipt of an application to the issuance of a license to operate would be approximately nine years.

The different timelines for smaller SMRs is reflective of CNSC requirements for the design and safety of new nuclear reactors that are somewhat different depending on the design thermal capacity rating of the reactor:

- For small reactor facilities less than approximately 200 MW_{th}, RD-367 (CNSC 2011a) provides the design requirements and RD-308 (CNSC 2011b) provides the safety analysis requirements. The StarCore SMR (28 MW_{th}, 14 MW_e) evaluated in this study as a reference HTGR and the NuScale SMR (160 MW_{th}, 47.5 MW_e) evaluated in this study as a reference iPWR would fall into this category.

- For water-cooled reactor facilities having greater than approximately 200 MW_{th}, REGDOC-2.5.2 (CNSC 2014) provides the design requirements and RD-310 (CNSC 2008b) provides the safety requirements. The SMART SMR (330 MW_{th}, 100 MW_e) evaluated as a reference iPWR in this study would fall into this category.

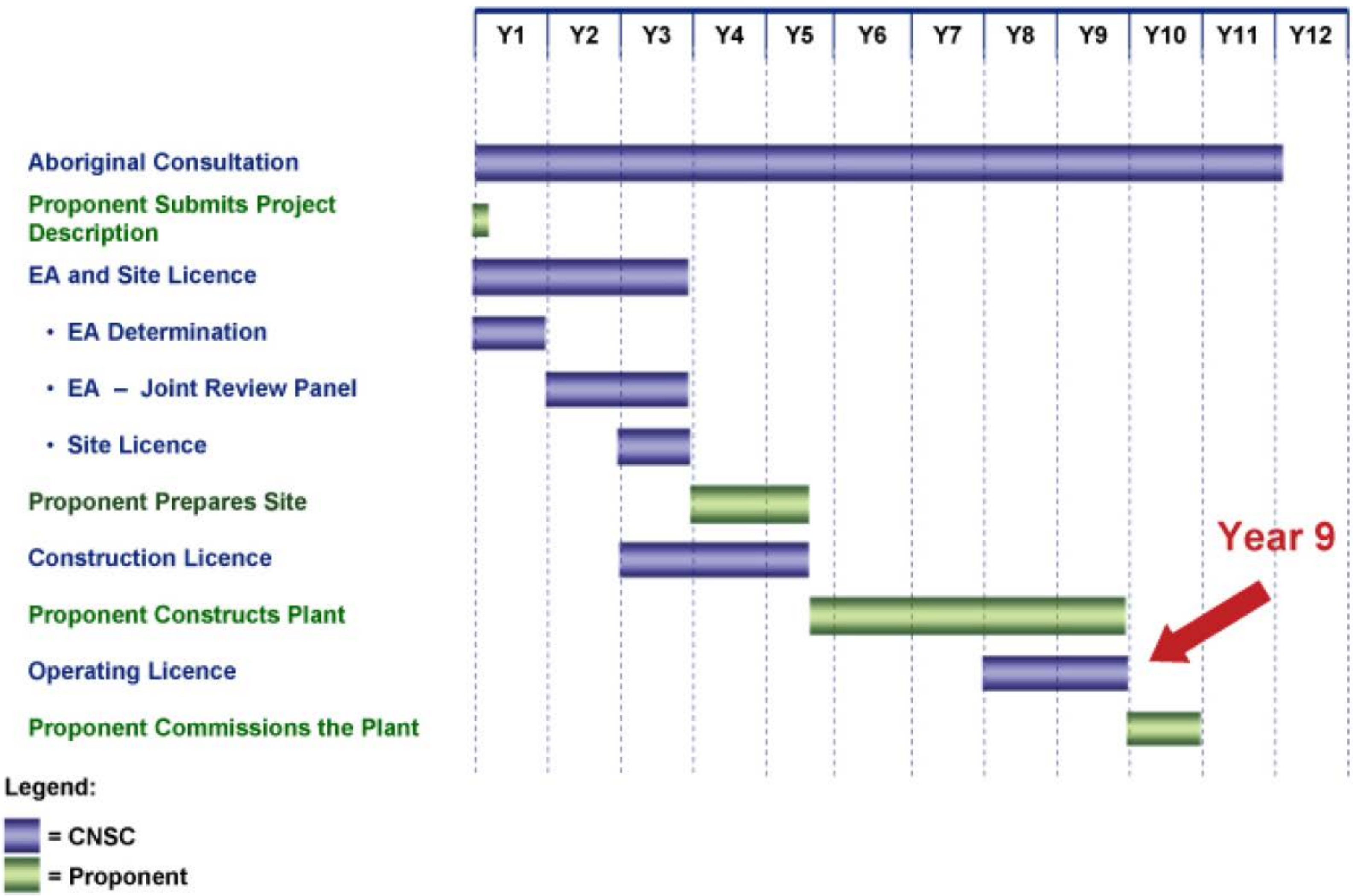

Figure 5-3. CNSC Licensing Process Timeline for a New Nuclear Power Plant

For non-water-cooled reactor facilities having greater than approximately 200 MW_{th}, REGDOC-2.5.2 (CNSC 2014) provides the design requirements and RD-310 (CNSC 2008b) provides the safety requirements although additional regulatory requirements may be needed (CNSC 2015). The SC-HTGR SMR (625 MW_{th}, 272 MW_e) evaluated as a reference HTGR in this study would fall into this category. It is noted in Figure 5-3 that the time from submission of a new SMR project to CNSC to receiving a construction license from CNSC is assumed to be about five years[35], and that a construction time period of about four years is assumed. It is reasonable to expect that after the first SMR application, CNSC review and approval of subsequent applications using the same SMR technology would require less time. For example, SMR vendors are claiming construction time periods of two to three years after experience is gained on the first plants, which could potentially reduce the timeline by one to two years. In addition, issuance of a construction license could be reduced by a year or more because of reduced time needed by CNSC to review the design if the design has already been previously reviewed/approved by CNSC (while the fundamental SMR design may be unchanged, some design changes will always be required to account for differences in the characteristics of a new proposed site). These potential reductions in the timeline may also be possible with the first SMR project in Canada depending on the extent to which the SMR construction experience and regulator reviews/approvals in other countries are acceptable to CNSC.

Unlike the design requirements for large water-cooled nuclear facilities in REGDOC-2.5.2, RD-367 provides for the use of a graded approach to the design of small reactor facilities. [Note: CNSC has stated that the use of the graded approach for SMRs > 200 MW_{th} is still possible, although REGDOC-2.5.2 will apply (CNSC 2011d)]. The graded approach is a risk-informed method in which the stringency of the design measures and analyses applied is commensurate with the level of risk posed by the reactor facility (i.e., using alternative approaches to meeting design and safety requirements). Nevertheless, designs using the graded approach are still required to demonstrate that they meet the safety objectives and the requirements set out in RD-367. When a graded approach is applied, factors to be considered include reactor power, reactor safety characteristics, amount and enrichment of fissile and fissionable material, fuel design, type and mass of moderator, reflector and coolant, utilization of the reactor, presence of high energy sources and other radioactive and hazardous sources, safety design features, source term (quantity of radioactive isotopes in the fuel), siting, and proximity to populated areas (CNSC 2011a). While RD-367 is a relatively recent requirements document, the graded approach is not new to CNSC in that it has been used in the past to license a variety of small reactor facilities in Canada (e.g., Chalk River NRU reactor (135 MW_{th}) (CNSC 2013).

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[35] From CNSC 2008a. About 3 years is required to complete the following: (1) develop the terms of reference for the Joint Review Panel to prepare the EA and develop instructions to the applicant on how to prepare the Environmental Impact Statement (EIS), (2) conduct public comment period on these documents, (3) applicant prepares and submits the EIS, (4) review of the EIS by the public and other stakeholders, which may include preparation and submittal of additional information by the applicant as needed until the Panel is satisfied that the intent of the EIS Guidelines is met, (5) develop the EA, (6) conduct public hearings on the EA, (7) finalize the EA report and issue the *License to Prepare Site*. About 2.5 years is required to complete the following: (1) CNSC staff review of the construction license application, which includes design documentation, Preliminary Safety Analysis Report (PSAR), the construction program, and other information required by regulations, (2) preparation and submittal of additional information by the applicant as requested by CNSC staff, (3) CNSC staff verification that outstanding issues from the site preparation stage have been resolved, (4) develop reports on the results of the CNSC staff's reviews, and (5) CNSC issues final decision on issuance of the construction license. This review may take place in parallel with the Environmental Assessment and site preparation licensing process.

Finally, as discussed in previous sections of this report, while the SMART and NuScale iPWR designs have not been submitted to the CNSC for review and licensing, each has been reviewed or is currently being reviewed by the national nuclear regulatory of the home countries of the reactor vendors. Specifically, the SMART reactor design has been reviewed and approved by the South Korean nuclear regulator and the NuScale reactor design is currently being reviewed by the U.S. NRC. Also, while not evaluated in this report, the CAREM-25 iPWR demonstration reactor is currently under construction in Argentina, with expected operation in 2018, and the HTR-PM demonstration HTGR SMR is currently under construction in China, also with expected operation in 2018. While the design reviews by these other national regulators are not a substitute for meeting CNSC requirements, CNSC has indicated that crediting design reviews by other national regulators can potentially facilitate their review (CNSC 2011c).

5.3 SMR Logistical Challenges

One of the potential challenges of applying nuclear reactors in the Alberta oil sands is the remoteness of the oil extraction and processing facilities and the associated lack of infrastructure for transporting SMR components to the oil sands. For example, the integral reactor pressure vessel modules for the reference SMRs evaluated in this report weight between 303 tonnes for the NuScale Power Module™ (height of 25 m, diameter of 4.6 m) to 825 tonnes for the SC-HTGR reactor vessel (height of 24 m, diameter of 6.5 m), with the weight of the SMART integral RPV having a weight between these of 750 tonnes (height of 18.5 m, diameter of 6.5 m). The dimensions of the StarCore reactor module are height of 6.5 m and diameter of 2.5 m (the weight is unknown). Other large components may also need to be transported, for example, the two steam generators for the SC-HTGR (Note: the steam generators for the NuScale and SMART designs are integral to the reactor vessels and so are included in the associated weights and dimensions of those components). This challenge was discussed in a 2008 report that evaluated the feasibility of nuclear energy options in the Albert oil sands (SNC•Lavalin 2008). Some specific observations from this report are repeated here:

- Shipping large and heavy components from their points of manufacture to the designated Oil Sands location may require the construction of special roadways and other infrastructure to facilitate shipping.

- Shipping times may also be set by environmental considerations (ground frost thickness, weather, etc.). Detailed transportation studies are typically completed as part of the site qualification program.

- Main line rail service is available from Vancouver and Duluth Minnesota to Edmonton.

    - The horizontal clearance is limited on these routes (approximately 4 meters from Vancouver and 4.3 meters from Duluth).

    - The highest capacity rail car available for shipping nuclear components is Schnabel's 36 axle rail car designed by Combustion Engineering, and currently owned by Westinghouse. This special rail car has a capacity of over 1000 tons, and can accommodate load lengths of up to 35 meters.

- Although there are small rail lines serving the Oil Sands region from Edmonton, no information was obtained on their capabilities.

- A detailed shipping strategy will be required as part of the project planning and scheduling.

Based on this information, which was not updated or verified for this study, the horizontal clearance limitation on available rail routes to the oil sands currently precludes rail shipment of the NuScale Power Module™, the SC-HTGR reactor vessel, and the SMART integral RPV. The StarCore reactor vessel, however, appears to be capable of being shipped by rail via either of the two routes evaluated.

This study also considered the feasibility of shipping large components via truck to the oil sands. In both Canada and the U.S., legal weight and size limits are established by individual provinces or states. Generally these legal limits are about 36 tonnes maximum gross vehicle weight, less than 2.6 m width, 4 m height, and 17.5 m length, but may be set lower/higher based on the route. However, payloads larger than this are permissible and are common, but are considered oversize and/or overweight shipments and require special permits. Overweight limits are determined based on a number of factors, such as the number of axles and the distance between the front and back axles. Typical overweight/oversize loads for which permit fees are published reach upper limits of about 68 tonnes, 4.9 m width, 4.9 m height, and 46 m length. Still larger loads are also permitted and are referred to as super loads or mega loads. Shipments of super/mega loads are not common, but are also not rare, and so each state/province has an established process for approving and permitting these super/mega payloads. As mentioned above, a detailed shipping strategy is necessary to ensure that the payload does not exceed weight limits along the route (e.g., bridges) and that there are no interferences with the proposed height/width/length of the payload (e.g., overhead street lights). In some cases, the owner of the payload may incur costs for temporarily or permanently moving interferences or for constructing routes around the interferences or weight-limiting structures.

With specific regard to truck shipments of super/mega loads to the oil sands in Canada and other locations in the western U.S., there are several pertinent examples:

1) In 2013/2014 two megaloads of oil sands-destined equipment, one being a heat exchanger for a water purification system, were shipped to Fort McMurray, Alberta, Canada from the manufacturer in Portland, Oregon, USA. The heat exchanger weighed 410 tonnes and had a length of 116 m. The shipments were barged up the Columbia River from Portland to Umatilla, Oregon and then transported by truck shipment through Oregon, Idaho, and Montana before crossing into Alberta, Canada (Missoulian 2013, Boise State Public Radio 2013).

2) In 2011 two megaloads of oil refinery equipment, both being one-half of a coke drum, were shipped to the ConocoPhillips facility in Billings, Montana, USA from Japan. The coke drums each weighed 315 tonnes, height of 7.9 m, and a width of 8.8 m. The shipments were barged up the Columbia and Snake Rivers to Lewiston, Idaho, USA and then transported by truck through Idaho and Montana (WYNC 2011).

3) In 2014 a megaload of oil-refining equipment, one of three portions of a reactor to form a hydrocracker unit, was shipped to the Calumet refinery in Great Falls, Montana, USA from the

manufacturer in Italy (the other two sections were shipped by rail). The equipment weighed about 490 tonnes, height of 5.1 m, width of 6.4 m, and a length of 122 m (Great Falls Tribune 2014). The shipment was barged up the Columbia and Snake Rivers to Lewiston, Idaho, USA and then transported by truck through Idaho and Montana (Great Falls Tribune 2014, Missoulian 2014).

While never completed, a shipping company had planned on making three megaload shipments of equipment through Idaho and Montana in 2014 that was eventually cancelled due to public opposition. Each of these shipments were planned to be 726 tonnes, width of 8.2 m, and height of 4.9 m (Missoulian 2013).

Based on this information, the NuScale NPM is well within the size and weight of equipment that have been shipped by truck to the oil sands in Alberta and other locations in the western U.S. Since there appears to be no technical limit to the size capable of being shipped by truck, with careful route consideration megaloads the size of the SMART integral reactor vessel appear to also be technically feasible, although it may be preferable to ship this reactor vessel as two or three smaller components and assemble it onsite. Lastly, megaloads the size of SC-HTGR RPV have not been demonstrated, and would likely need to be shipped as three to four smaller components and assembled onsite.

As a final note, megaloads can generate public opposition, especially when they pass through sensitive wilderness country. This consideration needs to be accounted for when planning shipment routes.

5.4 Used Nuclear Fuel and Radioactive Waste Management

There are two general categories of nuclear waste generated by nuclear power reactors: 1) used nuclear fuel waste and 2) intermediate- and low-level radioactive waste (I/LLRW). Used nuclear fuel is only produced by nuclear reactors and is the residual nuclear fuel that is removed from the reactor after it is no longer effective at producing energy. I/LLRW is any non-fuel radioactive waste and can be produced by any user/producer of nuclear materials, such as hospitals, research facilities, etc. The management and disposition of each in Canada is discussed below.

Used Nuclear Fuel Management

As with any nuclear power plant, all SMRs generate used nuclear fuel that is highly radioactive. The amount of used fuel generated each year depends on a number of factors, including the type of reactor (e.g., iPWR, HTGR), the size of the reactor in terms of power output, the type of fuel used, and the time period between refuelings. For the iPWRs evaluated in this study, the average amount of used fuel generated each year for a single module is estimated to be between one and three tonnes (0.5 to one m^3). A single module SC-HTGR is expected to annually generate used fuel having somewhat less mass but higher volume on average due to differences in fuel design.

Because used nuclear fuel remains hazardous (highly radioactive) for thousands of years, it must be maintained in safe long-term interim storage outside of the reactor until its final disposition. Canada does not yet have a final disposition path for used nuclear fuel. Hence, used nuclear fuel is currently kept in onsite interim storage facilities at each nuclear power plant site. As of June 30, 2017, a total of approximately 55,000 tonnes of used nuclear fuel was in storage at 11 reactor sites in Canada (NWMO 2017).

The Nuclear Waste Management Organization of Canada (NWMO), which is funded by generators of used nuclear fuel in Canada, is responsible for designing and implementing a plan for the safe, long-term management of all used nuclear fuel generated in Canada. The NWMO was established in 2002 under the Nuclear Fuel Waste Act to investigate approaches for managing Canada's used nuclear fuel. In June 2007, the Government of Canada selected Adaptive Phased Management (APM) as Canada's plan for the long-term management of used nuclear fuel. The NWMO is responsible for implementing this plan.

According to NWMO's website (NWMO 2017b):

> "APM is both a technical method and a management system for the final disposition of used nuclear fuel. The end point of the technical method is the centralized containment and isolation of Canada's used fuel in a deep geological repository in an area with suitable geology and an informed and willing host. APM also involves the development of a transportation system to move the used fuel from the facilities where it is currently stored to the new site. The management system involves realistic, manageable phases, each marked by explicit decision points. It allows for flexibility in the pace and manner of implementation, and fosters the sustained engagement of people and communities throughout its implementation."

Since 2010, NWMO has been engaged in a multi-year, community-driven process to identify a site that is willing to host the deep geologic repository. Several potential sites are currently being studied. The current schedule is for operation of a deep geologic repository to begin in the 2040-2045 time frame (NWMO 2017c). While this is a Canadian national facility for the disposal of used nuclear fuel, it is currently only being funded by the current major owners of used nuclear fuel in Canada. Therefore this facility may or may not be available for the disposal of used nuclear fuel generated from SMRs deployed in the Alberta oil sands applications. If not available, then a separate deep geologic repository may need to be developed in Alberta for used nuclear fuel from SMRs deployed in Alberta.

Radioactive Waste Management

As with nuclear power plants generally, SMRs generate radioactive waste during plant operations and during final decommissioning, but which is substantially less radioactive than used nuclear fuel. The amount of radioactive waste generated each year depends on a number of factors, including the type of reactor (e.g., iPWR, HTGR), the number of systems/equipment that are contaminated during plant operations, and the type of fuel used. The amount of I/LLRW generated annually from the operation of the SMR concepts evaluated in this study is not clear since none have yet been built. However, the amount of I/LLW generated from the operation of the large PWR's in the U.S. is generally between 100 and 500 m^3/year per reactor unit (USNRC 2006). Because iPWRs have less operating equipment and a smaller operating staff, the annual volumes of I/LLW is expected to be somewhat less. For HTGRs, the volume is expected to be substantially less because of the use of helium as the coolant rather than water.

Because I/LLW can remain hazardous for 100-500 years, it must be managed in a safe and environmentally responsible manner during this time period. The delegation of responsibilities for the management of I/LLW is set forth in the Government of Canada's Radioactive Waste Policy Framework (1996), which is as follows (NRC 2015):

> "The elements of a comprehensive radioactive waste policy framework consist of a set of principles governing the institutional and financial arrangements for disposal of radioactive waste by waste producers and owners.
>
> - The federal government will ensure that radioactive waste disposal is carried out in a safe, environmentally sound, comprehensive, cost-effective and integrated manner.
> - The federal government has the responsibility to develop policy, to regulate, and to oversee producers and owners to ensure that they comply with legal requirements and meet their funding and operational responsibilities in accordance with approved waste disposal plans.
> - The waste producers and owners are responsible, in accordance with the principle of "polluter pays", for the funding, organization, management and operation of disposal and other facilities required for their wastes. This recognizes that arrangements may be different for nuclear fuel waste, low-level radioactive waste and uranium mine and mill tailings."

The CNSC responsibility in this framework is to license, regulate, and monitor Canada's I/LLW waste management facilities to ensure that they are operated safely. The owners/operators of nuclear reactor facilities are responsible for "funding, organization, management and operations" of I/LLW storage and disposal facilities, and any other facilities required for the management of this waste.

There are currently no disposal facilities in Canada for I/LLW generated from the operation and decommissioning of nuclear reactor facilities. Hence, I/LLW is currently kept in onsite interim storage facilities at each nuclear power plant site. However, I/LLW disposal facilities are under active development. For example, Ontario Power Generation (OPG) is developing a deep geologic repository to dispose of 200,000 m^3 of I/LLW waste generated by OPG owned and operated nuclear generating stations in Ontario (OPG 2017). OPG has completed the preliminary design, environmental impact statement, and preliminary safety analysis report and is currently going through final review and approval processes by the Government of Canada. Based on an estimated construction period of 5 to 7 years, operation of this repository is expected in the mid-2020s. Another example is the development of a near surface disposal facility at the Chalk River Laboratory site for the disposal of about one million cubic meters of I/LLW generated predominantly at Canadian Nuclear Laboratories (CNL)-managed sites but also at various Canadian hospitals, universities, and others (CNL 2017). Operation of this facility is scheduled to begin by 2020.

Since I/LLW generators are responsible for "funding, organization, management and operations" of I/LLW storage and disposal facilities, it seems unlikely that I/LLW generated from SMRs deployed in the Alberta oil sands applications would be acceptable for disposal at these other facilities that are currently under development. It may be necessary to develop a disposal facility located in Alberta for I/LLW generated by SMRs deployed in the oil fields applications.

5.5 Nuclear Supply Chain

The nuclear supply chain, in the context of this study, refers to all of the equipment, components, raw materials, fabrication capability, design and construction expertise, and infrastructure needed to construct and operate a nuclear power plant. Because of the very high quality requirements specified by national nuclear regulations for many of the components that make up a nuclear power plant, vendors, suppliers, designers, and constructors of nuclear components and structures must develop and maintain high cost quality assurance programs to ensure that these quality requirements are met. Due to the high upfront cost of developing and maintaining these quality assurance programs, and the lack of new nuclear build projects in North America and Europe over the last 30 years, the nuclear supply chain in these regions has diminished appreciably during this time period.

Nevertheless, because of the large numbers of operating LWRs in North America and Europe, a qualified supply chain still exists for providing the replacement parts and services, including nuclear fuel and large components such as steam generators, needed to sustain and maintain the safe operation of these plants. In addition, because certain regions of the world currently have large new build projects (e.g., China, Russia, India, and the Middle East), a supply chain has developed to support these projects. For these reasons, and because iPWR plants and nuclear fuel are largely based on extensively deployed PWR technology, the lack of an available supply chain is not considered a significant issue for building iPWR plants. However, challenges do exist including:

- The consolidation of the nuclear supply chain over the last 30 years has "internationalized" the supply chain thereby complicating processes for ensuring that CNSC quality assurance requirements are met.

- The Canadian domestic construction labor force that is qualified for nuclear plant construction is currently limited and may have to be further developed to support timely construction of SMR plants.

- iPWR designs do incorporate specialized components that will require development of a supply chain for these components. For example, the NuScale Power Module™ and helical coil steam generators are new specialized components that will require new fabrication capability. Nevertheless, existing nuclear supply vendors, with necessary quality assurance qualifications, are expected to be available to meet these needs.

A larger supply chain issue exists for SMRs utilizing HTGR technology. As has been mentioned previously in this report, industrial-scale HTGRs have not been built or operated in almost 30 years. Hence, specialized components unique to HTGRs are unlikely to be readily available from the existing nuclear supply chain and to require supply chain development to support deployment of HTGR SMRs. Examples of supply chain challenges include (AREVA 2017):

- commercial scale manufacturing capability for TRISO fuel, which is significantly different than LWR fuel,

- production of high assay low enriched uranium (i.e., uranium enriched to up to 20% Uranium-235), which is higher enrichment than used in LWR fuel,
- availability of nuclear-grade graphite, and
- fabrication of helium turbomachinery (i.e., turbine/compressor).

It is noted that China will complete construction and startup of two HTR-PM pebble-bed HTGRs in Spring 2018 (each 250 MW_{th}/105 MW_e). In support of the operation of these demonstration HTGR SMRs, China has developed indigenous TRISO fuel fabrication capability on a scale sufficient to support continuous on-line refueling operations.

6.0 Conclusions and Recommendations

This report has considered and evaluated three potential applications of SMR technologies in the Alberta oils sands: (1) providing the electricity and medium/low pressure process steam requirements for a 200,000 bbl/d reference facility for surface mining of the oil sands bitumen extraction using either paraffinic or naphathanic froth treatment methods, (2) providing the high temperature process steam requirements for a 33,000 bbl/d reference facility for in-situ recovery of bitumen using SAGD, and (3) providing the electricity and high temperature heat requirements for a 200,000 bbl/d reference bitumen upgrading facility. The 26 SMRs evaluated in the Phase I report (PNNL 2016) were considered for each of these applications, from which reference SMRs were selected based on several factors. Principal among these factors were the technical capability of the technology to provide the electricity, process steam, and/or process heat requirements for the reference facility applications and the technology readiness level or expected availability of SMR technologies to provide timely support to the Government of Alberta Climate Change Leadership Plan goals to limit greenhouse gas emissions from oil sands operations.

Following selection of the reference SMR technologies for each of the oil sands applications, each of the selected technologies was evaluated in more detail to develop estimates, as applicable, of the overnight cost, levelized cost of electricity, levelized cost of hydrogen production, and staffing levels using publicly-available information. These metrics were then used to assess the economic competitiveness of each of the SMR technologies relative to the reference technologies currently used in the oil sands. Lastly, certain specific potential challenges with deploying SMRs in the oil fields were investigated. Important conclusions from this study are as follows:

1) SMR technologies are capable of providing the electricity, process steam, high temperature steam, and hydrogen requirements of the reference oil sands facilities evaluated in this study.

    a. iPWRs are especially well suited to produce the electricity and medium/low pressure process steam requirements for the oil sands mining and extraction facility application.

    b. HTGRs are especially well suited to produce the high temperature steam requirements for the oil sands SAGD facility application. While not specifically evaluated, HTGRs can also produce the required electricity, which is a small demand relative to the demand for high temperature steam.

    c. HTGRs are especially well suited to meet the H_2 requirements for the oil sands bitumen upgrading facility application.

2) SMR technologies are expected to be available and deployable in a time frame to play an important role in meeting the overall oil sands emission limit of 100 megatonnes.

    a. iPWRs are based on existing PWR technology, including nuclear fuel technology, which has thousands of reactor years of operating experience around the world. In essence, most of the accident safety basis and technology is available today. Furthermore, several iPWR designs have completed or are currently undergoing review by the national nuclear regulator (e.g., the

NuScale iPWR is currently undergoing design certification review by the U.S. NRC). As a result, iPWR technology is expected to be deployable well before 2030.

b. HTGRs technologies capable of producing high temperature steam are based on actual but limited operational experience. Most of the current HTGR designs are utilizing fuel technology that is demonstrated to be "intrinsically" safe. Qualification testing of the nuclear fuel to meet strict nuclear regulator requirements is actively progressing in multiple countries (e.g., China, U.S., Japan). Also, two demonstration HTGRs (250 MW_{th} each) are expected to start operation in China by Spring 2018 and StarCore has applied to CNSC for vendor design review status. As a result, HTGR technology is expected to be deployable before 2030.

c. HTGRs in combination with the HTSE water-splitting process is expected to be deployable before 2030. Hydrogen production is most efficient at very high temperatures (greater than about 850°C). HTGRs that are expected to be commercially deployable before 2030 have operating temperatures of about 750°C. Very High Temperature Gas Reactors (VHTGRs) are not expected to be commercially deployable before 2030. However, the HTSE process has been demonstrated to maintain good efficiency at operating temperatures of 750°C and even lower.

d. The iPWR and HTGR technologies were selected based on their TRL and commercial deployability by 2030, and on their capability to provide the electricity, steam, and hydrogen requirements for the Alberta oil fields applications. However, other advanced SMR technologies are currently under active development throughout the world that are potentially applicable to the oil sands applications, but which were judged to not be commercially deployable by 2030. These technologies include sodium fast reactors, molten salt reactors, gas-cooled fast reactors, and heavy liquid metal-cooled fast reactors, of which selected reactor concepts for each were evaluated in the Phase I report (PNNL 2016). Should expansion of oil production from the Alberta oil fields continue after 2030, or more restrictive limits be placed on GHG emissions from the Alberta oil fields after 2030, reconsideration of these technologies at an appropriate time would be prudent.

3) SMR technologies are not currently cost competitive with natural gas cogeneration of electricity and process steam for the surface mining facility application, with natural gas-fired OTSG for production of high temperature steam for the SAGD application, or with StMR production of hydrogen for the bitumen upgrading application, even after crediting a carbon price of C$30/tonne CO_2 (at the natural gas price of C$3.25/GJ assumed in this study for the surface mining facility and SAGD applications, and C$5.0/GJ assumed for the hydrogen production for bitumen upgrading application).

a. The LCOE for the NuScale iPWR plant is estimated to range from C$125-136/MW-hr (2014), or C$24.7-26.8/tonne steam, which depends on the iPWR technology and number of modules per plant. Estimates of the LCOE for natural gas cogeneration in the oil fields applications range from about C$80/MW-hr (2014) to C$95/MW-hr (2014), which accounts for the price of carbon emissions. On this basis, the cost of iPWR technology is estimated to be higher than natural gas cogeneration by C$10-60/MW-hr (2014). Unlike with natural gas cogeneration, where the largest cost component is the natural gas fuel, the largest cost components of the LCOE for a nuclear power plant project is the cost of financing construction of the plant and income/property taxes. For this analysis, assumptions on financing costs (31%) and income/property taxes (16%) contribute almost 50% to the total LCOE. Further assessment of the appropriateness of these costs for the oil sands surface facility application is recommended. Assuming no reductions or improvements in the cost of iPWRs, it is estimated that the price of natural gas would have to increase to C$7.5-8.0/GJ for iPWRs to become economically competitive with natural gas cogeneration.

b. The LCOE for the SC-HTGR plant is estimated to range from C$110-180/MW-hr (2014), with a best estimate of C$140/MWe (C$30-50/tonne steam, with a best estimate of C$37/tonne steam). Estimates of the LCOE for natural gas cogeneration in the oil fields applications range from about C$80/MW-hr (2014) to C$95/MW-hr (2014), accounts for the price of carbon emissions. On this basis, the cost of HTGR technology is estimated to be higher than natural gas cogeneration by C$15-100/MW-hr (2014) with a best estimate of C$50/MW-hr. Similar to the LCOE for the NuScale iPWR above, financing costs and income/property taxes contribute about 50% of the total LCOE. The same recommendation to assess the appropriateness of the assumptions used to develop the cost estimates for these cost accounts for the oil sands SAGD application is recommended. Assuming no reductions or improvements in the cost of HTGRs, it is estimated that the price of natural gas would have to increase to C$10.5-11.0/GJ for HTGRs to become economically competitive with natural gas-fired OTSGs.

c. The $LCOH_2$ for the SC-HTGR/HTSE integrated plant is estimated to range from C$6.4-6.9/$kgH_2$ (2014). The cost of hydrogen production using natural gas StMR is estimated to range from C$2.2-2.3/$kgH_2$ (2014) after accounting for the price of carbon emissions. On this basis, the cost of SC-HTGR/HTSE technology is estimated to be higher than natural gas cogeneration by C$4.1-4.7/$kgH_2$ (2014), or a factor of 3 to 3.5 higher.

d. The uncertainty in the SMR cost estimates reported in this study are large, predominantly because SMRs have not yet been deployed on an industrial scale. Furthermore, the cost estimates reflected in this study are generally based on cost estimates developed for SMRs producing baseload electricity supplied to the national power grid, further increasing the uncertainty in the cost estimates reported for the Alberta oil fields applications. In addition, the Alberta oil fields are generally located in remote northern locations of Canada, with its associated frigid winter weather conditions. These geographical and weather factors have not been evaluated or incorporated into the SMR cost estimates reported in this study. While the impact of these factors on SMR costs is not known, they would be expected to increase both the capital and operating costs of SMRs reported in this study.

e. Since neither iPWRs or HTGR SMRs have yet been deployed on an industrial scale, resulting in the associated cost estimates having significant uncertainty, it is recommended that the development and deployment of these technologies throughout the world be monitored. Actual deployment implies potential economic competitiveness with competing technologies and improved understanding of the cost of SMR technologies. Specific SMR technologies that show promise of being commercially deployed by 2030 include:

i. iPWRs: 1) construction of the first ACP-100 in China is scheduled to begin in 2018, 2) construction of the first CAREM-25 in Argentina is expected be completed in 2018, 3) the NuScale design is currently being reviewed by the U.S. NRC and operation of the first unit is anticipated for 2026, and 4) the SMART design has been reviewed and approved by the South Korean nuclear regulator and is actively being marketed in the Middle East.

ii. HTGRs: 1) construction of the two-unit HTR-PM in China is expected to be completed in 2018, 2) conceptual design of the HTR50S in Japan, which is based on the HTTR test reactor, has been initiated, 3) StarCore of Canada has submitted an application to the CNSC for pre-licensing design review, 4) the SC-HTGR was selected by the Next Generation Nuclear Plant (NGNP) industry alliance for near-term commercialization, and 5) the conceptual design of the Xe-100 in the U.S. has been initiated.

4) The estimated FTE staffing levels to operate and maintain SMRs having sufficient capacity to support the Alberta oil fields applications is estimated to be between 166 and 360 FTEs. Many of these staff require specialized training and skills that are unique to nuclear plant operation. Both the number of required staff and the specialized skill/training required by many of these staff may pose a challenge to the oil sands operations due to the remoteness of these facilities.

5) The use of a graded approach for licensing of SMRs by CNSC, and the VDR process being made available to reactor vendors by CNSC, holds promise of reducing the approximately 9 year licensing process for large water-cooled reactors to 6-7 years for SMRs. These review and approval timelines can potentially be reduced by 2-3 years if SMR construction time periods of two to three years are achievable (compared to over 4 years assumed in the CNSC timeline) and if issuance of a construction license by CNSC can be reduced by a year or more because the SMR design has either been previously reviewed by the CNSC or regulator design reviews/approvals in other countries are acceptable to CNSC.

6) Truck shipments of very large (up to 7.9 m height, up 8.8 m width, up to122 m long) and heavy (up to 500 tonnes) components to remote locations, generally oil refineries, in the Western U.S. and in Alberta, Canada from northwestern ports in the U.S. have been successfully demonstrated, holding promise for similar shipments of reactor components. However, these types of shipments generally have some public opposition, especially if the transport route is through sensitive wilderness areas. These types of shipments therefore do require very careful route planning and good communication with local authorities to avoid or minimize shipping delays.

7) The current schedule for the start of operation of a deep geologic repository for used nuclear fuel is in the 2040-2045 time frame. However, while this is a Canadian national facility for the disposal of used nuclear fuel, it is currently only being funded by the current major owners of used nuclear fuel in Canada. Therefore, this facility may or may not be available for the disposal of used nuclear fuel generated from SMRs deployed in the Alberta oil sands applications. If not available, then a separate deep geologic repository may need to be developed in Alberta for used nuclear fuel from SMRs deployed in Alberta. Also, since I/LLW generators are responsible for "funding, organization,

management and operations" of I/LLW storage and disposal facilities, it seems unlikely that I/LLW generated from SMRs deployed in the Alberta oil sands applications would be acceptable for disposal at other facilities that are currently under development in Canada. It may be necessary to develop a disposal facility located in Alberta for I/LLW generated by SMRs deployed in the oil fields applications.

8) The lack of an available supply chain is not considered a significant issue for building iPWR plants. However, challenges do exist including: 1) globalization of the supply chain has complicated processes for ensuring that CNSC quality assurance requirements are met, 2) a domestic construction labor force that is qualified for nuclear plant construction may need to be developed to support timely construction of SMR plants, and 3) specialized iPWR components (e.g., the NuScale Power Module™ and helical coil steam generators) will require development of a supply chain before these SMRs can be deployed. However, a larger supply chain issue exists for SMRs utilizing HTGR technology. Examples of supply chain challenges include (AREVA 2017): 1) commercial scale manufacturing capability for TRISO fuel, which is significantly different than LWR fuel, 2) production of high assay low enriched uranium (i.e., uranium enriched to up to 20% Uranium-235), which is higher enrichment than used in LWR fuel, 3) availability of nuclear-grade graphite, and 4) fabrication of helium turbomachinery (i.e., turbine/compressor).

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Appendix A

Summary of Design and Operational Features of SMRs Evaluated in the Phase I Study

Appendix A

Summary of Design and Operational Features of SMRs Evaluated in the Phase I Study

This appendix provides a summary of design and operational features of the 26 SMRs evaluated in the Phase I study. Table A-1 provides the summary for each of these SMRs. Refer to the Phase I report (PNNL 2016), for more details about each of the 26 SMR designed. Acronyms used in Table A-1 are as follows:

CB – Containment Building

CR – Control Room

CSS – Concrete Shield Structure

CV – Containment Vault

FLiBe – $2LiF\text{-}BeF_2$ (lithium fluoride – beryllium fluoride salt)

LBE – Lead-Bismuth Eutectic Alloy

N/A – Not Available

PCS – Primary Coolant System

RB – Reactor Building

SFP – Spent Fuel Pool

SG – Steam Generator

ThO_2 – Thorium Dioxide

TRU – Transuranic Elements

U – Uranium

UF_4 – Uranium Tetrafluoride

UO_2 – Uranium Dioxide

VDR – ventor design review

Zr – Zirconium

Since completion of the Phase I report, TerraPower of the U.S. and China National Nuclear Corporation (CNNC) have signed an agreement to develop TerraPower's traveling wave reactor (TWR) design, which is a sodium-cooled fast reactor. The standard TerraPower reactor design is 600 MWe, which does not meet the definition of an SMR (less than about 300 MWe). However, the announcement indicates that a 300 MWe version of the TerraPower reactor design is under consideration. No further information is available on this potential new SMR concept.

Table A-1. Design and Operational Features of the SMRs Evaluated in Phase I

SMR Technology	TRL	Estimated Time to Commercialization (years)	Fuel Type / Enrichment (%)	Reactor Coolant / Moderator	Reactor Coolant Outlet Temperature (°C)	Power Conversion Process	Load Following Capability?
Integral Pressurized Water Reactors (iPWRs)							
ACP-100 (CNNC), China	5-6	5 to 10	UO_2 17x17 / 4.2	Light Water	323.4	Indirect Rankine Cycle	N/A
mPower (B&W Generation), USA	5-6	10 to 15	UO_2 17x17 / <5.0	Light Water	318.8	Indirect Rankine Cycle	Yes
CAREM-25 (CNEA), Argentina	5-6	5 to 10	UO_2 Hexagonal / 3.1	Light Water	326	Indirect Rankine Cycle	N/A
FBNR (FURGS), Brazil	1-2	20+	Cermet UO_2 / 5.0	Light Water	326	Indirect Rankine Cycle	N/A
SMR-160 (Holtec), USA	2-3	10 to 15	UO_2 17x17 / 4.95	Light Water	316	Indirect Rankine Cycle	Yes
NuScale (NuScale Power), USA	5-6	5 to 10	UO_2 17x17 / <4.95	Light Water	N/A	Indirect Rankine Cycle	Yes
SMART (KAERI), Korea	6-7	0 to 5	UO_2 17x17 / <5	Light Water	323	Indirect Rankine Cycle	Yes
Westinghouse SMR (Westinghouse Electric Co.), USA	4-5	10 to 15	UO_2 17x17 / <5	Light Water	324	Indirect Rankine Cycle	Yes
Heavy Water Reactors (HWRs)							
AHWR300-LEU (BARC), India	3-4	10 to 15	UO_2+ThO_2 cylindrical / 19.75	Light Water / Heavy Water	285	Rankine Cycle	Yes
PHWR-220 (NPCIL), India	9-10	Already Deployed	UO_2 cylindrical / natural	Heavy Water / Light Water	293	Indirect Rankine Cycle	No
High Temperature Gas-cooled Reactors (HTGRs)							
GT-HTR300 (JAEA), Japan	5-6	15 to 20	TRISO Prismatic-block	Helium / Graphite	850 - 950	Direct Brayton Cycle	Yes
GT-MHR (OKBM Afrikantov), Russia	5-6	15 to 20	TRISO Prismatic-block	Helium / Graphite	850	Direct Brayton Cycle or Indirect Rankine Cycle	Yes, 33 - 100%
HTR50S (JAEA), Japan	7-8	5 to 10	TRISO Prismatic-block	Helium / Graphite	750 or 900	Direct Brayton Cycle or Indirect Rankine Cycle	Yes
HTR-PM (Tsinghua University), China	7-8	5 to 10	TRISO Pebble-bed	Helium / Graphite	750	Indirect Rankine Cycle	Yes, 50 - 100%
SC-HTGR (AREVA), USA	5-6	10 to 15	TRISO Prismatic-block	Helium / Graphite	750	Rankine Cycle	Yes
StarCore (StarCore Nuclear), Canada	1-2	15 to 20	TRISO Prismatic-block	Helium / Graphite	850	Indirect Rankine Cycle	Yes
Xe-100 (X-energy), USA	4-5	10 to 15	TRISO Pebble-bed	Helium / Graphite	750	Indirect Rankine Cycle	Yes
Molten Salt Reactors (MSRs)							
IMSR (Terrestrial Energy), Canada	3-4	15 to 20	UF_4 within liquid carrier salt	Fluoride Salt / Graphite	700	Superheat Rankine Cycle	Yes
TMSR-SF (SINAP), China	3-4	15 to 20	TRISO Pebbles	FLiBe / Graphite	700	N/A	Yes
TMSR-LF (SINAP), China	2-3	20+	UF_4 within liquid carrier salt	FLiBe / Graphite	700	N/A	Yes
Heavy Liquid Metal-cooled Fast Reactors (HLMCs)							
G4M (Gen4 Energy), USA	2-3	20+	U Nitride ceramic / 19.75	LBE / None	500	Indirect Rankine Cycle	Yes
SVBR-100 (AKME Eng.), Russia	3-4	20+	UO_2 Hexagonal / 16.7	LBE / None	490	Indirect Rankine Cycle	Yes
Gas-cooled Fast Reactors (GFRs)							
EM^2 (General Atomics), USA	3-4	20+	UC hexagonal / ~12	Helium / None	850	Combined Brayton-Rankine Cycle	Yes
Sodium-cooled Fast Reactors (FSRs)							
4S (Toshiba), Japan	6-7	5-10	U-Zr alloy hexagonal / 12 - 19	Sodium / None	510	Indirect Rankine Cycle	Yes
PGSFR (KAERI), Korea	4-5	15-20	U-TRU-Zr metal / 19.2	Sodium / None	545	Indirect Rankine Cycle	Yes
PRISM (GE-Hitachi), USA	5-6	10-15	U-Pu-Zr metal / N/A	Sodium / None	485	Indirect Rankine Cycle	Yes

Table A-1. Design and Operational Features of the SMRs Evaluated in Phase I (Continued)

SMR Technology	Number Modules per Plant	Steam Characteristics			Energy Production		Refueling Complexity		
		Temperature (°C)	Pressure (MPa)	Mass Flow Rate (kg/s)	Electrical Capacity (MWe)	Thermal Capacity (MWth)	On-site or Off-site	Time Between Refueling Outages (months)	Duration of Refueling Outages (days)
Integral Pressurized Water Reactors (iPWRs)									
ACP-100 (CNNC), China	1 to 8	>290	4.0	125	100	310	On-site	24	40
mPower (B&W Generation), USA	2	299.4	5.7	267	180	530	On-site	48	15
CAREM-25 (CNEA), Argentina	1	290	4.7	N/A	27	100	On-site	14	N/A
FBNR (FURGS), Brazil	N/A	N/A	N/A	N/A	72	218	Off-site	25	N/A
SMR-160 (Holtec), USA	1	299	2.3	195	160	525	On-site	36 - 48	5
NuScale (NuScale Power), USA	1 to 12	300	3.5	67	45	160	On-site	24	10
SMART (KAERI), Korea	2	298	5.2	160.8	100	330	On-site	36	36
Westinghouse SMR (Westinghouse Electric Co.), USA	1	N/A	N/A	N/A	>225	800	On-site	24	17
Heavy Water Reactors (HWRs)									
AHWR300-LEU (BARC), India	1	285	7.0	408	304	920	On-site	On-line Continuous Refueling	On-line Continuous Refueling
PHWR-220 (NPCIL), India	2	250.6	4.03	369	236	755	On-site	On-line Continuous Refueling	On-line Continuous Refueling
High Temperature Gas-cooled Reactors (HTGRs)									
GT-HTR300 (JAEA), Japan	1 - 4	N/A	N/A	N/A	100-300	<600	On-site	24	30
GT-MHR (OKBM Afrikantov), Russia	2	N/A	N/A	N/A	285	600	On-site	25	25
HTR50S (JAEA), Japan	N/A	538	12.5	N/A	17	50	On-site	24	N/A
HTR-PM (Tsinghua University), China	2	566	13.2	186	105	250	On-site	On-line Continuous Refueling	On-line Continuous Refueling
SC-HTGR (AREVA), USA	1 - 4	566	16.7	281	272	625	On-site	18 - 24	25
StarCore (StarCore Nuclear), Canada	2	N/A	N/A	N/A	14	28	Off-site	60	N/A
Xe-100 (X-energy), USA	2 - 8	565	16.5	50	76	200	On-site	On-line Continuous Refueling	On-line Continuous Refueling
Molten Salt Reactors (MSRs)									
IMSR (Terrestrial Energy), Canada	1	N/A	N/A	N/A	32.5 / 141 / 291	80 / 300 / 600	Off-site	84	0
TMSR-SF (SINAP), China	N/A	N/A	N/A	N/A	45	100	N/A	N/A	N/A
TMSR-LF (SINAP), China	N/A	N/A	N/A	N/A	45	100	N/A	N/A	N/A
Heavy Liquid Metal-cooled Fast Reactors (HLMCs)									
G4M (Gen4 Energy), USA	1	480	N/A	N/A	25	70	Off-site	10 years	N/A
SVBR-100 (AKME Eng.), Russia	4	278	6.7	161	101	280	On-site	7 - 8 years	N/A
Gas-cooled Fast Reactors (GFRs)									
EM^2 (General Atomics), USA	4	N/A	N/A	N/A	265	500	On-site	32 years	Not Applicable
Sodium-cooled Fast Reactors (FSRs)									
4S (Toshiba), Japan	1	453	10.5	12.7	10 / 50	30 / 135	On-site	30 years	Not Applicable
PGSFR (KAERI), Korea	1	503	16.7	171.4	150	192.2	On-site	12	N/A
PRISM (GE-Hitachi), USA	2	452	14.7	380.3	311	840	On-site	N/A	N/A

Table A-1. Design and Operational Features of the SMRs Evaluated in Phase I (Continued)

SMR Technology	Remote Operation?	Regulatory - Licensing Complexity: Conventional Reactor Technology?	Regulatory - Licensing Complexity: Inherent or Passive Safety / Grace Period	Security/Safety Features: Type of Containment	Security/Safety Features: Forced or Natural Circulation of Coolant	Security/Safety Features: Structures and Components Underground
Integral Pressurized Water Reactors (iPWRs)						
ACP-100 (CNNC), China	No	Yes, PWR with passive safety features	Passive / 72 hours	CB	Forced	CB & SFP
mPower (B&W Generation), USA	No	Yes, PWR with passive safety features	Passive / 72 hours	CB	Forced	CB, CR, & SFP
CAREM-25 (CNEA), Argentina	No	Yes, PWR with passive safety features	Passive / 36 hours	CB	Natural	None
FBNR (FURGS), Brazil	No	No, Unconventional PWR	Passive / > one month	CB	Forced	CB
SMR-160 (Holtec), USA	No	Yes, PWR with passive safety features	Passive / Unlimited	CB	Natural	Reactor Pressure Vessel & SFP
NuScale (NuScale Power), USA	No	Yes, PWR with passive safety features	Passive / Unlimited	CV	Natural	Reactor Pool, CR, & SFP
SMART (KAERI), Korea	No	Yes, PWR with passive safety features	Passive / 36 hours	CB	Forced	None
Westinghouse SMR (Westinghouse Electric Co.), USA	No	Yes, PWR with passive safety features	Passive / 7 days	CV	Forced	Containment Pool & SFP
Heavy Water Reactors (HWRs)						
AHWR300-LEU (BARC), India	No	Yes, CANDU w/ passive safety features	Passive / 7 days	CB	Natural	Calandria Vessel
PHWR-220 (NPCIL), India	No	Yes, CANDU	No Passive	CB	Forced	None
High Temperature Gas-cooled Reactors (HTGRs)						
GT-HTR300 (JAEA), Japan	No	No, limited HTGR experience	Inherent Safety	RB or CSS	Forced	Portion of RB Containing PCS
GT-MHR (OKBM Afrikantov), Russia	No	No, limited HTGR experience	Inherent Safety	CB	Forced	CB
HTR50S (JAEA), Japan	No	No, limited HTGR experience	Inherent Safety	RB or CSS	Forced	Portion of RB Containing PCS
HTR-PM (Tsinghua University), China	No	No, limited HTGR experience	Inherent Safety	CB	Forced	None
SC-HTGR (AREVA), USA	No	No, limited HTGR experience	Inherent Safety	Reactor Silo	Forced	Reactor Silo
StarCore (StarCore Nuclear), Canada	Yes	No, limited HTGR experience	Inherent Safety	Concrete Silo	Forced	Concrete Silo
Xe-100 (X-energy), USA	No	No, limited HTGR experience	Inherent Safety	Concrete Structure	Forced	Portion of Concrete Structure Containing PCS and SFP
Molten Salt Reactors (MSRs)						
IMSR (Terrestrial Energy), Canada	No	No, essentially no MSR experience	Passive / long time	Concrete Containment Shell	Forced	N/A
TMSR-SF (SINAP), China	No	No, essentially no MSR experience	Passive / long time	N/A	Forced	N/A
TMSR-LF (SINAP), China	No	No, essentially no MSR experience	Passive / long time	N/A	Forced	N/A
Heavy Liquid Metal-cooled Fast Reactors (HLMCs)						
G4M (Gen4 Energy), USA	No	No, HLMC experience only in Russia	Passive / 2 weeks	Reactor Vault	Forced	Reactor Vault and SG
SVBR-100 (AKME Eng.), Russia	No	No, HLMC experience only in Russia	Passive / 4 days	Concrete Well	Forced	Concrete Well
Gas-cooled Fast Reactors (GFRs)						
EM^2 (General Atomics), USA	No	No, no GFR experience	Passive / Unlimited	CSS	Forced	CSS
Sodium-cooled Fast Reactors (FSRs)						
4S (Toshiba), Japan	No	No, limited SFR experience	Passive / Unlimited	Reinforced Concrete RB	Forced	RB
PGSFR (KAERI), Korea	No	No, limited SFR experience	Passive / extended time	CV	Forced	None
PRISM (GE-Hitachi), USA	No	No, limited SFR experience	Passive / Unlimited	CV within Concrete Silo	Forced	CV within Concrete Silo

Table A-1. Design and Operational Features of the SMRs Evaluated in Phase I (Continued)

	Levelized Cost				
SMR Technology	**Electricity, US$/MW-hr (year of cost estimate)**	**Steam, US$/1000 pounds steam (year of cost estimate)**	**Hydrogen, US$/kg (year of cost estimate)**	**Development status**	**SAGD Ranking (High - 1, Low - 0)**
Integral Pressurized Water Reactors (iPWRs)					
ACP-100 (CNNC), China	N/A	N/A	N/A	Component test done; Construction site is planned	0.49
mPower (B&W Generation), USA	88 - 96 (2013)	N/A	N/A	Some component test done; Design certificate application not submitted	0.49
CAREM-25 (CNEA), Argentina	N/A	N/A	N/A	Under construction; Fuel irradiation/hydraulic CRD need to be tested	0.50
FBNR (FURGS), Brazil	N/A	N/A	N/A	No components /fuel tested	0.48
SMR-160 (Holtec), USA	N/A	N/A	N/A	Testing facility under construction	0.43
NuScale (NuScale Power), USA	98 - 108 (2015)	N/A	N/A	Design application submitted to NRC in Dec 2016; Most testing done; Construction begin in 2019, Start of operations in 2023	0.56
SMART (KAERI), Korea	61 (2007)	N/A	N/A	Testing done, Design approved	0.51
Westinghouse SMR (Westinghouse Electric Co.), USA	N/A	N/A	N/A	Draw technology from approved AP1000 design; Testing plan approved	0.42
Heavy Water Reactors (HWRs)					
AHWR300-LEU (BARC), India	N/A	N/A	N/A	Testing on passive cooling/fuel is underway; Demo plant construction in 2016/2017	0.42
PHWR-220 (NPCIL), India	N/A	N/A	N/A	16 units running in India	0.37
High Temperature Gas-cooled Reactors (HTGRs)					
GT-HTR300 (JAEA), Japan	58 - 64 (2011)	N/A	N/A	30MWth testing Rx run since 1998,shutdown in 2011	0.67
GT-MHR (OKBM Afrikantov), Russia	N/A	N/A	N/A	Looking for funding sources for further development	0.65
HTR50S (JAEA), Japan	N/A	N/A	N/A	Ready for commercial deployment; based on existing test reactor	0.74
HTR-PM (Tsinghua University), China	N/A	N/A	N/A	Commercial unit under construction	0.64
SC-HTGR (AREVA), USA	80 (2014)	16 - 17 (2014)	N/A	Based on development work at Idaho National Laboratory for Next Generation Nuclear Plant; Looking for funding sources for further development	0.65
StarCore (StarCore Nuclear), Canada	N/A	N/A	N/A	Development status unclear, no announcements of any significant funding sources	0.80
Xe-100 (X-energy), USA	84 (2015)	N/A	N/A	Conceptual design under development; testing being performed over next few years	0.61
Molten Salt Reactors (MSRs)					
IMSR (Terrestrial Energy), Canada	N/A	N/A	N/A	Phase 1 of pre-licensing VDR completed by CNSC in December 2017	0.67
TMSR-SF (SINAP), China	N/A	N/A	N/A	Construct experimental reactor in 2018; Construct demo reactor in mid-2020's	0.58
TMSR-LF (SINAP), China	N/A	N/A	N/A	Construction of test reactor in 2018; Construct experimental reactor in 2020s; Construct demonstration reactor in 2030's	0.54
Heavy Liquid Metal-cooled Fast Reactors (HLMCs)					
G4M (Gen4 Energy), USA	N/A	N/A	N/A	In conceptual design stage; prototype reactor planned for 2030	0.58
SVBR-100 (AKME Eng.), Russia	N/A	N/A	N/A	Startup of pilot plant planned for 2019, however, looking for funding sources	0.47
Gas-cooled Fast Reactors (GFRs)					
EM^2 (General Atomics), USA	67 (2014)	N/A	N/A	Conceptual design stage; Significant testing required; No announced schedule	0.66
Sodium-cooled Fast Reactors (FSRs)					
4S (Toshiba), Japan	50 - 70 (2009)	N/A	N/A	Vendor currently looking for a customer	0.77
PGSFR (KAERI), Korea	N/A	N/A	N/A	Construction of prototype reactor planned by 2028	0.51
PRISM (GE-Hitachi), USA	N/A	N/A	N/A	Reactor concept being marketed in United Kingdom to burn excess plutonium	0.61

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