Methodology, Risks and Drivers

Emerging Technology Drivers

AESO 2024 Long-Term Outlook

MAY 2024

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Hydrogen

Hydrogen as a fuel source for electrical generation may play a role in decarbonizing electricity but will be highly dependent on the availability of appropriate supporting infrastructure (i.e., transportation and storage) and will be driven primarily by long-term trends in production price related to manufacturing practices. While the use-cases for various colours of hydrogen (pertaining to their manufacturing methodology) are being widely assessed for technological readiness, there are few which currently warrant utility-scale consideration. Blue hydrogen, derived from a natural gas feedstock and created through steam methane reforming (SMR) or autothermal reforming (ATR), with back-end carbon capture and sequestration, is poised to be the most cost-competitive source of low-emissions hydrogen available at market scale.

Alberta is in a unique position to become a large-scale producer of blue hydrogen with access to plentiful natural gas feedstock, industrial expertise in hydrogen use and handling, and existing and planned infrastructure for carbon dioxide transport and geologic sequestration. With the inclusion of carbon capture and sequestration to the SMR/ATR process, the production of blue hydrogen also benefits from generating emissions offsets or emissions performance credits by overperforming *the Technology Innovation and Emissions Reduction* (TIER) *Regulations* high-performance benchmark for hydrogen production emissions intensity.

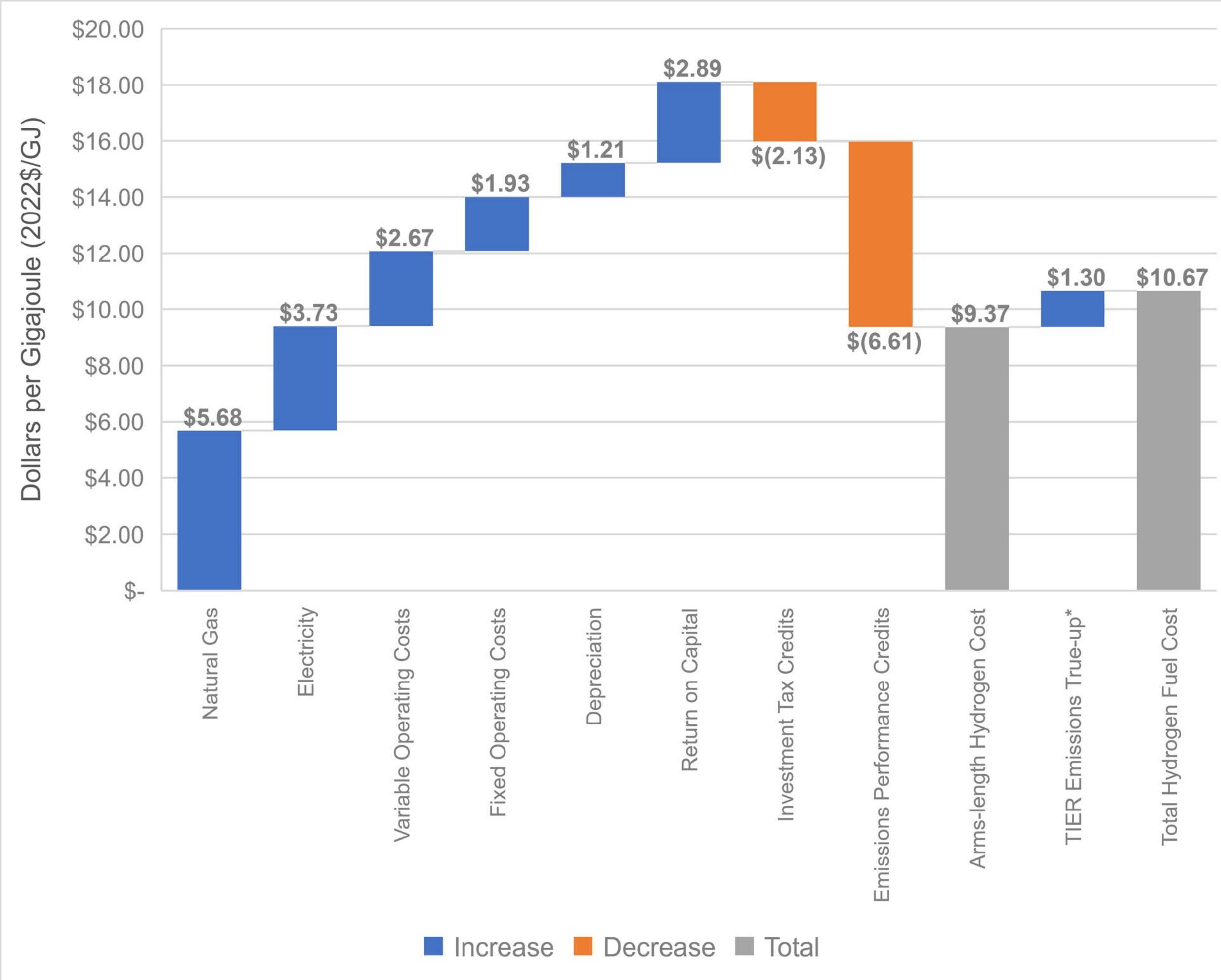
Alberta is home to a world-class blue hydrogen facility at the Shell Scotford (Quest) site which uses an SMR process to create blue hydrogen with carbon capture; this site has been operational since 2015.[1] Alberta is slated to get its next utility-scale blue hydrogen production facility in 2024 near Edmonton; a joint project between Air Products, the Government of Canada, and the Province of Alberta, deemed the Canada Net-zero Hydrogen Energy Complex.[2] The facility will use an ATR process with 90 per cent carbon capture and sequestration to produce approximately 100,000 tonnes of hydrogen annually. The AESO has developed a long-term cost projection model for blue hydrogen in Alberta based on capital and operating cost estimates for ATR from the National Renewable Energy Laboratory (NREL)[3] and adjusted capital costs to reflect available Clean Hydrogen Investment Tax Credits (ITC). Figure 1 shows the levelized cost of blue hydrogen production broken out by cost component. Captured carbon dioxide (CO_2) transportation and storage costs are considered for the financial analysis and are lumped into the variable operating cost category in Figure 1.

[1] For more details on the Shell Scotford (Quest) site, see https://www.shell.com/business-customers/catalysts-technologies/resources-library/quest-carbon-capture-plant.html.

[2] For more details on the Canada Net-zero Hydrogen Energy Complex, see https://www.airproducts.com/energy-transition/canada-net-zero-hydrogen-energy-complex.

[3] NREL H2A: Hydrogen Analysis Production Models. https://www.nrel.gov/hydrogen/h2a-production-models.html.

Figure 1: Levelized Cost of Blue Hydrogen, $/GJ (2022 Dollars)

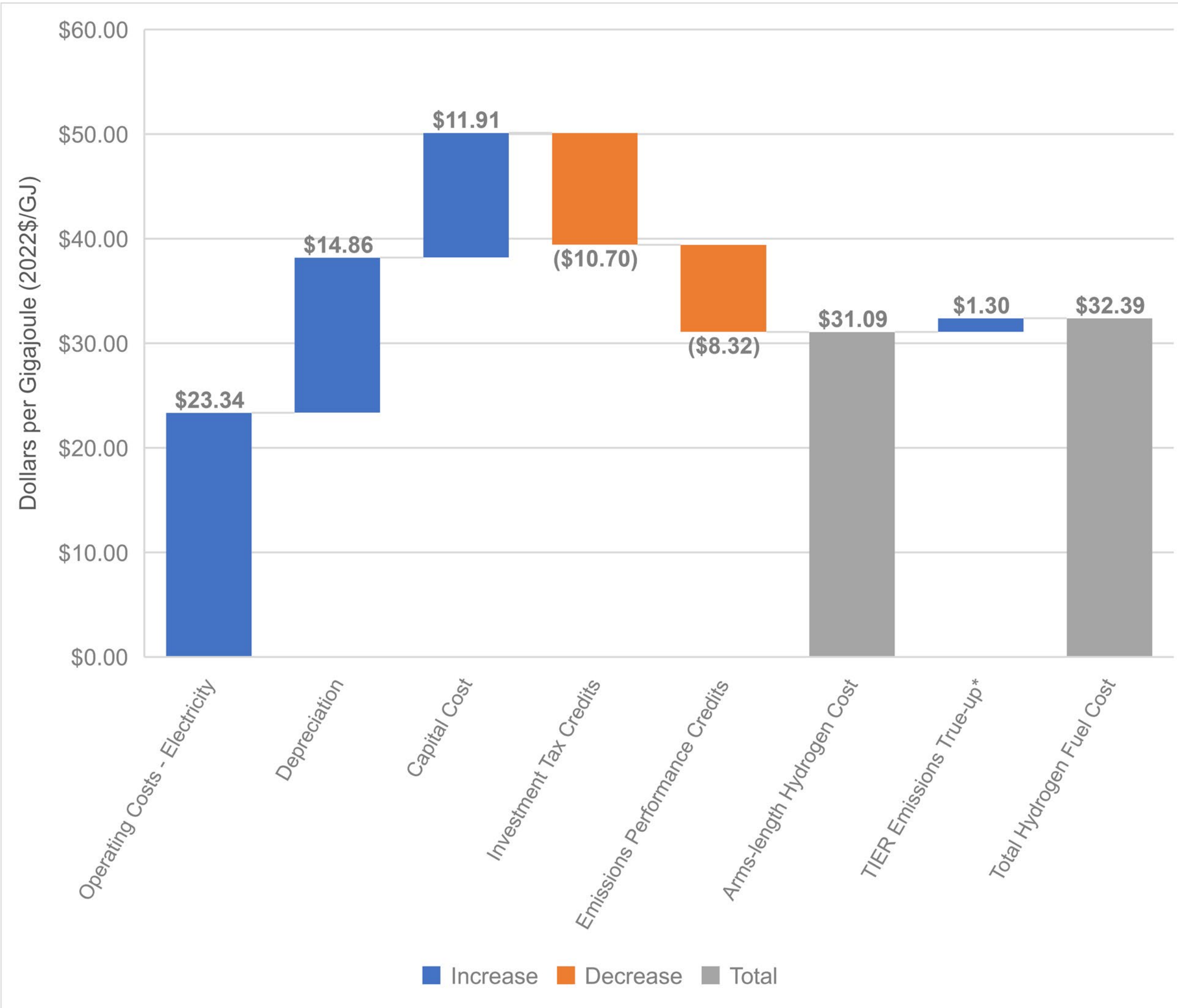


*TIER Emissions true-up based on 418 MW hydrogen fired combined cycle generator with 6.79 GJ/MWh heat rate operating at 85 per cent capacity factor

Alternatively, green hydrogen, which is produced by water-based electrolysis powered through renewable electricity sources (e.g., wind, solar), has zero process emissions and the potential to scale in grids where inverter-based resource penetration continues to increase. Green hydrogen facilities are expected to have a much shorter operational lifetime than blue hydrogen facilities due to voltage degradation in the electrolysis cell upon cycling, following similar trends to those found in lithium-ion batteries. As such, the current forecast operational life for a green hydrogen plant is expected to be approximately five years, whereas blue hydrogen facilities will likely operate for closer to 30 years. Using cost and performance data from the United States Department of Energy's 2022 Status Low-Cost Hydrogen Production Model,[4] the levelized cost of green hydrogen in the Alberta regulatory framework is presented in Figure 2.

[4] US Department of Energy, Technical Targets for Proton Exchange Membrane Electrolysis. https://www.energy.gov/eere/fuelcells/technical-targets-proton-exchange-membrane-electrolysis.

Figure 2: Levelized Cost of Green Hydrogen, $/GJ (2022 Dollars)



*TIER Emissions true-up based on 418 MW hydrogen fired combined cycle generator with 6.79 GJ/MWh heat rate operating at 85 per cent capacity factor

Omitted from the cost estimates above is the associated water feedstock cost for hydrogen production. This cost is regionally dependent, and its contracted value will vary by site and individual water lease agreement (if applicable). It is noted that it is expected to take roughly 10 litres of water to produce one kilogram of hydrogen for both blue and green hydrogen.[5] Feedstock electricity for green hydrogen is presumed to be sourced from wind generation at a levelized price of $60/megawatt hour (MWh) before taking into consideration any offsets or emissions performance credits related to the TIER high-performance benchmark for electricity. Under TIER, these credits are claimed via the allowable emissions for hydrogen

[5] Global CCS Institute (2021). Blue Hydrogen. https://www.globalccsinstitute.com/wp-content/uploads/2021/04/Circular-Carbon-Economy-series-Blue-Hydrogen.pdf.

production, which incorporates imported electricity and is based on the TIER high-performance benchmark for hydrogen. A weighted average cost of capital of 10.5 per cent is assumed in the fuel modelling and assets are depreciated on a straight-line basis over the operational lifetime of the plant.

The arm's length fuel price for hydrogen-fired generators in the province of Alberta does not include any emissions true-ups due to allowable emissions on the electrical generation side as prescribed under TIER. The true-up cost for a generic 418 megawatt (MW) hydrogen-fired combined cycle plant operating with a 6.79 gigajoules (GJ)/MWh heat rate at 85 per cent capacity factor is estimated to be $1.30/GJ levelized over a 30-year plant operational life.[6] The total price including the associated true-up (which will vary based on the efficiency of the turbine combusting the hydrogen) would represent the cost associated with using hydrogen as a fuel to produce electricity.

Another type of hydrogen production that is gaining interest, particularly in jurisdictions rich in natural gas feedstock but without easy access to geologic carbon sequestration sites and supporting infrastructure, is turquoise hydrogen. Turquoise hydrogen is manufactured using a process called methane pyrolysis that produces hydrogen and solid carbon byproducts at a less energy-intensive scale than both blue and green hydrogen. With a solid carbon byproduct, there is no need for expensive carbon capture and sequestration infrastructure on the output side of the manufacturing process. Additionally, the solid carbon generated in the pyrolysis process can be a commercially marketable product for use in various industries including as a base for graphite anodes in battery manufacturing, as well as in various metallurgical processes for the heavy chemicals industry (e.g., coking). Alberta is expecting its first-of-a-kind turquoise hydrogen facility through a partnership between Ekona Energy and ARC Resources at the Gold Creek natural gas plant in Grand Prairie.[7] This plant is expected to produce one tonne of hydrogen per day starting in 2026 based on Ekona's proprietary methane pyrolysis technology.

Carbon Capture, Utilization, and Storage (CCUS)

Several policy announcements intended to accelerate decarbonization across the economy have increased the urgency for emitting facilities to reduce their emissions intensity. These include draft federal regulations targeting the emissions intensity from facilities that use fossil fuels to generate electricity, a proposed federal cap-and-trade program on emissions from oil and gas production,[8] and an escalating carbon price.[9] CCUS offers the potential to mitigate greenhouse gas emissions from industrial processes and fossil fuel-based electricity generation. Carbon capture can occur pre-combustion (e.g., capturing residual CO_2 during blue hydrogen production) or post-combustion (e.g., capturing CO_2 from the exhaust of a process that combusts methane or other gasses, usually utilizing an amine-based solution). The captured CO_2 can then be either transported and stored underground (i.e., geological sequestration) or broken down and utilized for carbon-based products. CCUS technologies are likely to play a paramount role in emissions reductions in the oil

[6] Cost and operational characteristics derived from combustion turbine H class combined-cycle single shaft, 430 MW projections at https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

[7] For more details on the Ejona Plant One project, see https://majorprojects.alberta.ca/details/Ekona-Plant-One/11043.

[8] At the time of writing, draft regulations for the Oil and Gas Sector Greenhouse Gas Emissions Cap have not been published and are expected in 2024. As such, they were not included in the AESO's cogeneration forecast. Details on the proposed regulatory framework can be found at https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap/regulatory-framework.html.

[9] For more information on carbon pricing assumptions used in the 2024 LTO, see the Policy and Regulatory Drivers section.

sands sector in Alberta, especially with the announcement of a provincial grant for new CCUS projects that can be coupled with existing federal ITCs. These combine to total 62 per cent of the overnight capital cost of qualifying facilities until 2031, which may help drive the economics of such large-scale capital projects.[10]

Existing CCUS technologies integrated in Alberta on industrial sites include the Shell Quest project on the Scotford Upgrader, the Alberta Carbon Trunk Line for the Redwater and Sturgeon refineries, and the Entropy Glacier project, which captures post-combustion carbon from their generating units. The AESO continues to see interest in natural gas generators fitted with CCUS in its connection queue.

The 2024 LTO included CCUS projects on new natural gas-fired combined-cycle and cogeneration facilities, as well as retrofits to existing combined-cycle and cogeneration facilities. It is expected that adding CCUS to a combined-cycle unit will reduce overall generation output by about 10 per cent, approximately five per cent from diverting steam from a steam turbine to the CCUS unit, and approximately five per cent due to additional auxiliary electric load on the CCUS unit.[11] While reducing the carbon impact, CCUS also has the potential to impact the amount of generation available to the system. Note within the model load for the transportation of captured carbon to an offsite location is not accounted for and may be under represented within the analysis.

CCUS Additions to Existing Combined-Cycle Facilities

Existing large combined-cycle facilities are expected to retrofit with CCUS if the decision to do so is economic. The costs of installing CCUS were modeled based on an Energy Information Administration (EIA) report which compares the capital cost of a new facility with 90 per cent CCUS to the same facility without CCUS.[12] While acknowledging that retrofitting may incur higher CCUS integration costs associated compared to new facility construction, the specific details and experiences of retrofitted facilities remain limited and may evolve with technological advancements by the anticipated possibility of retrofitting as early as 2027.

CCUS Additions to Oil Sands Cogeneration Facilities

Oil sands facilities with existing cogeneration may explore retrofitting their electrical generation and integrated steam configurations with post-combustion, amine-based carbon capture technology, which uses steam as an input to the regeneration process in the carbon capture unit to reduce emissions intensity. Sites without existing cogeneration (e.g., in situ installations operating once-through steam generators [OTSGs] for steam injection) may explore retrofitting existing operations with post-combustion CCUS while continuing to import electricity from the Alberta Interconnected Electric System (AIES). Or sites may consider installing new standalone cogeneration with CCUS to supply on-site electrical load at compliant emissions intensity levels. Failure to abate process emissions for bitumen production will result in full exposure to the price of carbon at increasing levels annually.

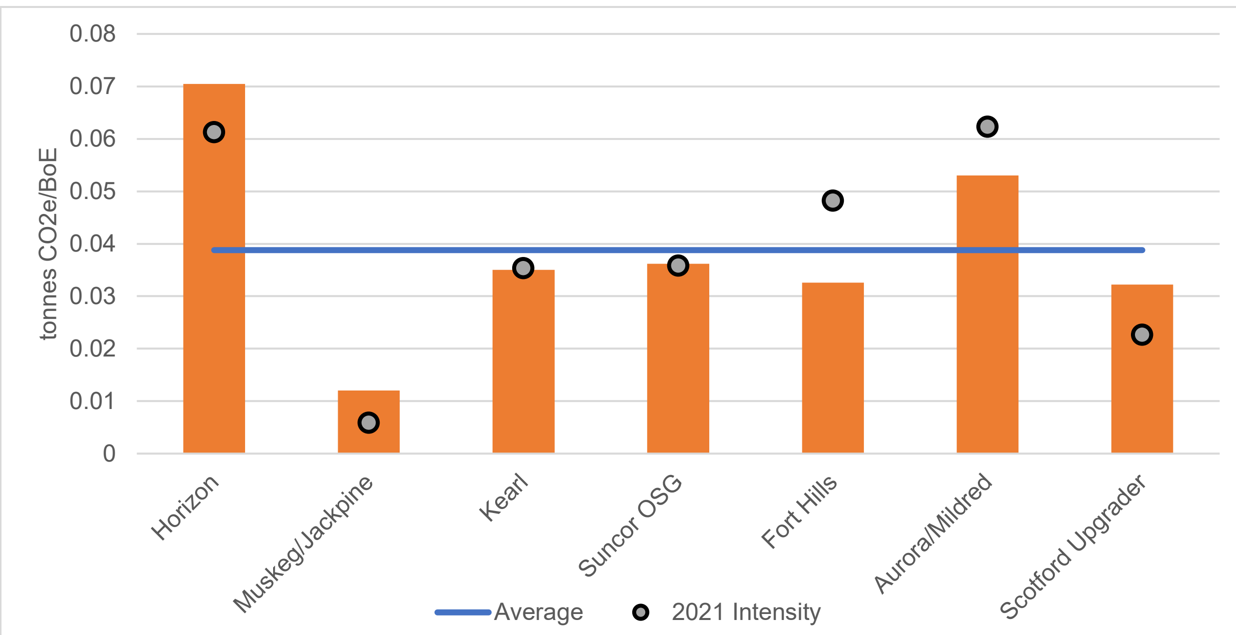
[10] For more information on investment tax credits used in the 2024 LTO, see the Policy and Regulatory Drivers section.

[11] EIA (2020). Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

[12] *Ibid.*

Under TIER,[13] large emitters that do not primarily produce electricity, heat, or hydrogen may apply for a facility-specific benchmark (FSB) which defines a baseline historical emissions intensity for the site. TIER prescribes an annual reduction schedule to this value based on facility type which sets the allowable emissions intensity for future years. The reduction target is set at 20 per cent and 14 per cent for mining/upgrading and in situ sites in 2023, respectively, increasing by two per cent annually until 2028 and four per cent annually thereafter.[14] Using historical bitumen production and steam injection numbers from the provincial mineable (ST39)[15] and in situ (ST53)[16] bitumen statistics reporting, FSBs were estimated for 28 oil sands sites which fall under unique greenhouse gas reporting identifiers (GHGRPID).[17] The average estimated FSB emissions intensity was calculated at 0.039 t CO_2e/BoE for mining/upgrading sites and 0.092 t CO_2e/BoE for in situ installations. In situ installations are over twice as emissions intensive as mining/upgrading sites due to the volume of natural gas combusted for process purposes related to wellhead steam injection. Allowable site emissions, as prescribed in TIER, and estimated actual emissions intensities (calculated using methodology from the Canadian Association of Petroleum Producers [CAPP][18]) were also estimated from provincial reporting data.

Figure 3: Estimated Facility-Specific Benchmarks (FSBs) for Alberta Upgrading and Mining Oil Sands Sites



[13] Facility-specific benchmarks are described in section 7 of TIER. https://kings-printer.alberta.ca/1266.cfm?page=2019_133.cfm&leg_type=Regs&isbncln=9780779843916.

[14] Standard for developing benchmarks (2023). https://open.alberta.ca/dataset/0cba733c-5038-4503-a2ef-33edb14abae3/resource/bf8d67ff-d925-4a75-a6c1-2dce1dfe42f1/download/epa-tier-standard-developing-benchmarks-version-2-2.pdf.

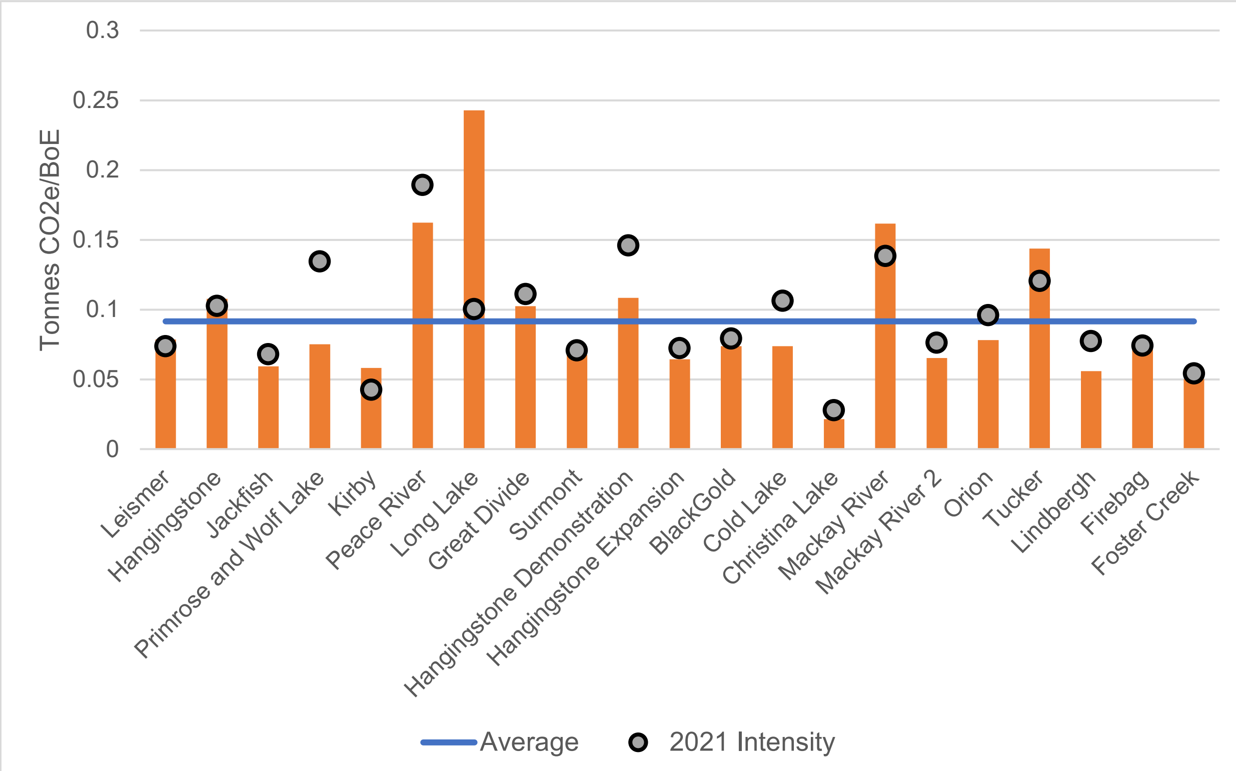
[15] AER ST39: Alberta Mineable Oils Sands Plants Statistics Monthly Supplement. https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st39.

[16] AER ST53: Alberta In Situ Oil Sands Production Summary. https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st53.

[17] The federal Greenhouse Gas Reporting Program data search is available at https://climate-change.canada.ca/facility-emissions/?GoCTemplateCulture=en-CA.

[18] CAPP (2021). Methodology for Calculating GHG Intensities. https://www.capp.ca/wp-content/uploads/2021/07/ESG-Emissions-Methodology.pdf.

Figure 4: Estimated Facility-Specific Benchmarks (FSBs) for Alberta In Situ Oil Sands Sites



Under TIER, CCUS projects can generate sequestration credits. Those credits can be treated like other emissions offsets or emissions performance credits (EPCs), but they can also be converted to capture recognition tonnes by the facility that originally captured the carbon. Capture recognition tonnes are deducted directly from a facility's total regulated emissions.[19] Facilities that use capture recognition tonnes to reduce their total regulated emissions below their associated FSB after adjusting for the prescribed TIER tightening schedule are assumed to generate offsets or emissions performance credits (EPCs) based on the prevailing federal price of carbon. It is assumed that these EPCs can be used against emissions in the overall portfolio of the energy producer and, as such, act as cost savings when considering the installation of abatement technologies. The AESO explored the financial tradeoff for sites without existing cogeneration to install cogeneration with post-combustion CCUS versus status-quo unabated operations. Given this regulatory framework, it may benefit these sites to install cogeneration with CCUS to satisfy on-site electrical and steam needs. The electrical needs of sites without existing cogeneration were estimated by baselining annual steam injection rates to in situ cogeneration sites with historically stable on-site loads (e.g., MEG Christina Lake). An additional component was added to total site electrical needs to reflect the parasitic load that would be present in a carbon capture system (based on the steam needs of a generic CCUS unit sized per MW of electrical capacity).[20]

[19] For more information on sequestration credits and capture recognition tonnes, see the Policy and Regulatory Drivers section.

[20] EIA *supra* note 11.

Table 1: Estimated Electrical Load of In Situ Facilities without Existing Cogeneration

Site	On-site Load (MW)	On-site Load with CCUS (MW)
Jackfish	64	66
Surmont	83	85
Kirby	41	42
Mackay River (PetroChina)	14	14
Peace River	3	3
Hangingstone	7	8
Hangingstone Demonstration	5	5
Hangingstone Expansion	15	16
Blackgold	5	5
Orion	14	15
Tucker	19	20
Total	270	279

Sites without existing cogeneration are currently assumed to import electricity at the prevailing pool price and incur an associated Demand Transmission Service (DTS)[21] charge for the imported electrical capacity. Electrical emissions intensity for these operations are thus linked to the Alberta Electricity Grid Displacement Factor (EGDF), which reflects the average emissions intensity of all assets across the grid and merges with the TIER high-performance benchmark for electricity as of the year 2030.[22]

Based on cost and performance data for generic simple-cycle generators and carbon capture units, and the face value of EPCs generated from carbon sequestration at a 93 per cent capture rate, adding CCUS to existing cogeneration or installing new cogeneration with CCUS was the cost preferable solution for all 28 analyzed sites; the reduction in carbon costs, whether or not the offsets or EPCs could be realized for their full monetary value, was greater than the cost of the CCUS installation over the lifetime of the project.

[21] https://www.aeso.ca/rules-standards-and-tariff/tariff/rate-dts-demand-transmission-service/.

[22]. For more information on TIER high-performance benchmark and electricity grid displacement factor assumptions used in the 2024 LTO, see the Policy and Regulatory Drivers section.

For sites without existing cogeneration, cost savings were further driven by the avoidance of energy charges and DTS payments from importing electricity from the AIES. This financial analysis assumes costs and performance associated with the installation of Solar Titan 130[23] simple-cycle turbines for cogeneration and that the size and cost of the units will scale exactly to the estimated electrical and steam needs of the individual facility.

While overbuilding electrical capacity may be advantageous in some situations, such as increased participation in the electricity market for net exporters, this behavior may fall outside of the business practices of some operators. Project costs for both the cogeneration and CCUS units are assumed to be depreciated over a 25-year operational lifetime at a weighted average cost of capital of 10.50 per cent.

Given an assumed four-to-five-year permitting and construction process for carbon capture projects in Alberta, the AESO forecasts the implementation of associated abated cogeneration in the 2028 to 2031 timeframe. This coincides with the timeline for reduction of federal ITCs for CCUS installations beginning in 2031 where the rate drops from 50 per cent to 25 per cent, further incentivizing a relatively near-term buildout of the technology. The result is 279 MW of additional cogeneration capacity, forecast to come online in the 2028 to 2031 timeframe from 11 in situ oil sands sites in the AESO forecast.

Oil sands sites with existing cogeneration facilities (e.g., CNRL Horizon, MEG Christina Lake) may also have a financial incentive to reduce emissions with the addition of post-combustion CCUS. Assuming that the CCUS units can be added to existing processes and sized to existing electrical capacity, the AESO forecast also develops a timeline for CCUS retrofits for these units. The capital cost of the CCUS addition is again incentivized by a total of 62 per cent reduction on overnight capital for the CCUS unit before 2031. Improvements in emissions intensity after the CCUS addition can lead to the development of EPCs for sequestered carbon, which may bring a facility's emissions intensity below its associated FSB. A 93 per cent capture rate is also assumed to ensure that emissions intensity post-capture would meet the 30 t CO_2e/GWh performance standard imposed by the draft *Clean Electricity Regulations* (CER),[24] allowing facilities who are net exporters to maintain existing behavior on the generation side. When comparing the costs of existing operations to retrofitting post-combustion carbon capture, it is again immediately economic for all sites to retrofit under the assumption that EPCs generated from the carbon capture unit can be consumed at face value in other parts of the operator's portfolio.

There is the possibility that the full value of EPCs generated from such projects would not be realized, as they are marketable assets and may trade at a discount to face value. Large amounts of EPCs generated by CCUS installations may also play a role in saturating the market for such offsets, in turn reducing their nominal value. Removing any EPC value generated by the installation of CCUS and comparing only the estimated costs of existing unabated operations to those that incur costs with the installation of cogeneration and CCUS yields the forecast installation timeline shown in Figures 4 and 5. This timeline shows the point in time where the annualized costs of CCUS installation becomes more economic than incurring costs associated with existing operations (i.e., paying the carbon price on emissions above the prescribed allowable level and importing electricity for sites without cogeneration). Retrofitting with CCUS on sites with existing cogeneration will incur an associated parasitic load component for the CCUS system

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[23] Specification for the Solar Titan 130 are available at https://www.solarturbines.com/en_US/products/power-generation-packages/titan-130.html.

[24] For more information on the CER and assumptions used in the 2024 LTO, see the Policy and Regulatory Drivers section.

at an assumed rate of 9.5 per cent of overall plant capacity. This results in approximately 290 MW of overall parasitic load for these sites which the AESO forecast interprets as a reduction to the nameplate capacity of the units. Given most sites with existing cogeneration are net exporters of electricity, they are assumed to possess enough headroom above required on-site load to accommodate the parasitic load of the CCUS unit without impacting overall generation behavior.

Figure 5: Timeline for Standalone CCUS Retrofits with No EPC Value Considered

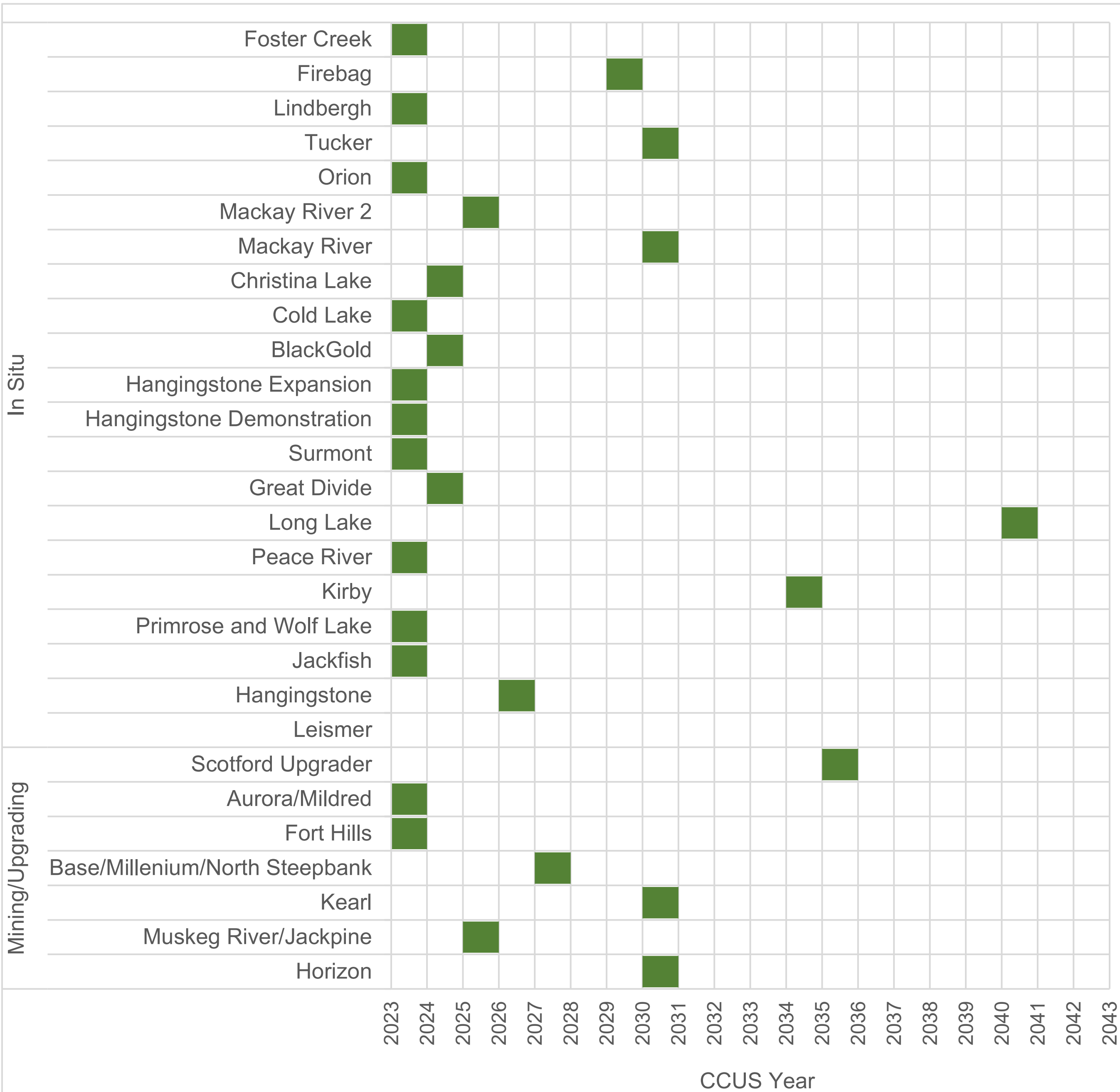
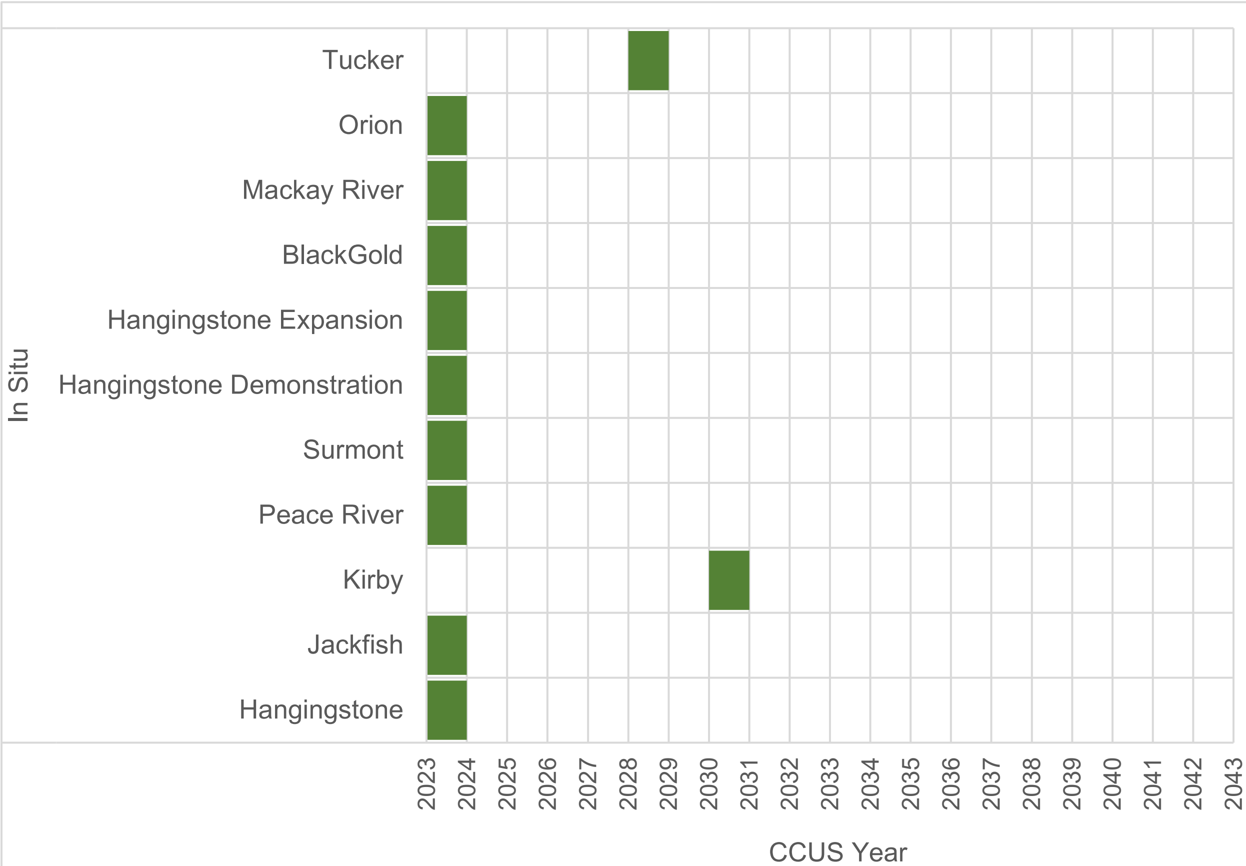


Figure 6: Timeline for Cogeneration with CCUS Installation with No EPC Value Considered



Foregoing the complete value of any EPCs generated from carbon capture shifts the economic installation timeline for some oil sands sites, but the vast majority still become economic to retrofit or install cogeneration on or before 2030. Given the savings from DTS and energy charge avoidance for sites without existing cogeneration combined with generous provincial and federal ITCs pre-2030, this result is intuitive. In this analysis, carbon price is assumed to increase linearly past 2030 and the EDC Associates Q4 2023 pool price forecast[25] is used to forecast the associated energy charge for electricity imports.

Nuclear Small Modular Reactors (SMRs)

In Canada, there has been a recent surge in interest regarding the adoption of nuclear technologies as an alternative to other existing power generation technologies. This enthusiasm is largely directed towards nuclear small modular reactors (SMRs), driven by their potential for reduced capital costs, scalability, flexibility, and enhanced safety features. SMRs are distinguished from traditional nuclear in that SMRs are smaller, typically under 300 MW, and, ideally, modular, meaning that parts can be fabricated off-site and shipped to and assembled on-site. Government support for SMRs has notably increased, with the Government of Canada committing to tripling energy from nuclear sources by 2050 during the 2023 COP28

[25] https://www.edcassociates.com/

conference. Alberta, with Ontario, Saskatchewan, and New Brunswick, released a *Strategic Plan for the Deployment of Small Modular Reactors*[26] in 2022, reflecting a broader trend of interest in maintaining and constructing nuclear facilities. Initiatives such as Ontario Power Generation's (OPG) submission of licensing for SMRs at the Darlington Facility, and partnerships like Cenovus and Capital Power with OPG, demonstrate a multi-faceted approach to exploring the feasibility and potential of SMRs. This interest is contrasted to a lack of interest in traditional large-scale nuclear reactors, mainly due to high capital costs, long build times, anticipated cost overruns, concerns about grid capacity and contingency requirements, and social pushback.

Under Alberta's current framework, traditional large-scale nuclear would be challenging to accommodate, mainly due to its relative size compared to the overall system, as traditional nuclear facilities are often 1,000 MW or greater. A 1,000 MW reactor supplying over eight per cent of Alberta's generation would be significantly challenging for grid stability in the event the facility tripped and disconnected from the grid. As such, this would represent the single largest contingency in Alberta, seconded only to a fully loaded intertie with British Columbia. Alberta currently has the most severe single contingency (MSSC) at 466 MW or the size of the maximum net generation that could be lost from a single point of failure while maintaining grid reliability. Assets larger than the MSSC would require specific mitigation to accommodate their operation at full capacity. SMRs are much smaller reactors, usually 300 MW or less, and could be more easily integrated into the grid. Additionally, SMRs are expected to have lower capital costs and shorter construction times, particularly if manufacturers can achieve modularity, possibly overcoming investment risks associated with traditional nuclear facilities. However, nuclear has faced barriers with respect to social acceptability (e.g., Bruce Power's 2011 proposal for a nuclear facility near Peace River which was withdrawn after public pushback). While SMRs are expected to be safer and produce less waste, they may still face social barriers to their development.

There are a number of emerging nuclear technologies, some of which align with established nuclear technologies, albeit on a smaller size, and others that are newer, such as reactors that utilize novel configurations or compounds like molten salt. The 2024 LTO nuclear forecast is modelled based on the GE-Hitachi BWRX-300 SMR technology,[27] which utilizes an established technology and is slated to be the reactor used at OPG's Darlington site, Canada's first SMR project. The AESO further used cost estimates for the BWRX-300 published by the manufacturer in 2019 on its estimated next-of-a-kind costs.[28] Thus, the 2024 LTO assumes a decreasing cost of capital between 2030 and 2050.

[26] A Strategic Plan for the Development of Small Modular Reactors (2022). https://open.alberta.ca/dataset/de9ebaba-81a7-456e-81a2-2c57cb11412e/resource/62319fa5-aa5a-4329-b980-5c85a924c7c7/download/energy-interprovincial-strategic-plan-deployment-of-smrs-2022.pdf.

[27] For more information on the GE-Hitachi BWRX-300, see https://www.gevernova.com/nuclear/carbon-free-power/bwrx-300-small-modular-reactor.

[28] Status Report – BWRX-300. (2019). https://aris.iaea.org/PDF/BWRX-300_2020.pdf.

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