AESO Cost of New Entry Analysis:

Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date

PREPARED FOR

ALBERTA ELECTRIC SYSTEM OPERATOR

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Executive Summary

The Alberta Electric System Operator (AESO) is proposing to implement a centralized three-year-forward capacity market with a first commitment period of November 2021 to October 2022. To that end, AESO retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to develop several key elements of the capacity market design. This report presents our estimates of the Cost of New Entry (CONE) in Alberta for new merchant generation resources.

The estimated CONE value represents the total annual net revenue (net of variable operating costs) that a new generation resource would need to earn in the Alberta wholesale electricity market to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. CONE is the starting point for estimating the Net Cost of New Entry (Net CONE). Net CONE represents the annual revenues that a new resource would need to earn specifically in the capacity market, after netting out energy and ancillary service (E&AS) margins from CONE.

CONE and Net CONE are used to "anchor" the AESO's administratively-set demand curve for capacity. Note, however, that the value AESO selects for Net CONE will not determine (nor predict) the capacity market clearing price. Rather, the market clearing price will depend on the offers that suppliers make into the capacity market auction as cleared against the demand curve.

To estimate the CONE value for the Alberta capacity market demand curve, AESO requested that Brattle and S&L: (1) identify candidate reference technologies for setting the CONE and Net CONE values; (2) develop bottom-up plant capital cost and operations and maintenance (O&M) cost estimates for each technology; (3) determine an appropriate discount rate and other financial assumptions to convert the estimated costs into the total annualized net revenues necessary to enter the market; and (4) calculate annualized CONE values for each reference technology. The AESO will then select the reference technology and estimate its E&AS margins in order to calculate Net CONE for the selected reference technology.

We reviewed a wide range of technologies that participate in the Alberta wholesale market and selected three reference technologies for setting Net CONE in the capacity market: (1) an aeroderivative combustion turbine (Aero CT) plant; (2) a frame-type combustion turbine (Frame CT) plant; and (3) a combined-cycle (CC) gas turbine plant. Each of these technologies is likely to be a part of the long-term equilibrium mix in Alberta as they have recently been added to the Alberta system and are currently being considered for future development. In addition, there are currently no inherent constraints to future development of these resources, and reliable cost information is available to support an accurate bottom-up cost estimate. While the Alberta market has a significant amount of cogeneration facilities and proposed coal-to-gas conversions, we excluded these technologies due to their non-standard costs and the inherent limits to future development of these resources, which can only be built either at retiring coal plants or by constructing new plants at industrial facilities. While reciprocating internal combustion engine (RICE) plants have recently entered the market, the total capacity in the market remains small compared to other gas-fired technologies. Finally, we screened out renewables (*e.g.*, solar and wind) due to their limited capacity value, demand response due to their non-standard costs, and energy storage due to the limited capacity deployed to date.

We developed complete plant designs for each of the three reference technologies that reflect the locations, technology choices, and plant configurations that developers are likely to choose as indicated by both operating and proposed projects. For the Aero CT design, we specify two GE LM6000-PF SPRINT turbines; for the Frame CT design, a single Siemens SGT6-5000F turbine. The reference CC design includes a single Siemens SGT6-8000H turbine in combination with a heat recovery steam generator and steam turbine ("1×1 configuration"). The chosen CC design is wet-cooled and includes a selective catalytic reduction (SCR) unit for pollution control. We assume all plants are "gas-only" and obtain firm gas transportation contracts to ensure sufficient fuel supply. We assume the plants are built in the greater Edmonton area due to the availability of gas and electric infrastructure, the availability of industrial land, access to water rights, and the recent development of gas-fired power plants in that region.

For each reference technology, we conduct a comprehensive, bottom-up analysis of the capital costs to build the plant assuming an November 1, 2021 online date: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, exchange-rate hedging costs, gas and electric interconnection costs, and inventories. We separately estimate annual fixed and variable O&M costs, including labor, materials, property taxes, and insurance. All of the cost estimates take into account Alberta-specific prices, ambient conditions, and construction requirements, including local labor rates and productivity factors, land costs and property taxes, freight costs, and gas and electric interconnection standards.

Finally, we translate the estimated capital costs into the annualized average net revenues the resource owner would have to earn over an assumed 20-year economic life to achieve its required return on and return of capital. We use a rate of 8.5% overall after-tax cost of capital for discounting the free cash flows of a merchant generation investment, which we estimated based on the very high end of the range associated with various cost of capital reference points for Canadian generation companies and U.S. independent power producers. All reference points include adjustments to reflect expected 2021 Canadian financial market conditions and the expected market cost of long-term (20-year) debt financing (rather than lower yields of shorter-term and in some cases higher-credit-quality bonds of the sample companies). The recommended cost of capital estimate thus accounts for forecasted 2021 Canadian market conditions, the cost of long-term debt financing, and the relative risk between the sample companies and a merchant generation plant operating in the proposed three-year forward Alberta capacity market. Assuming a 50% debt and 50% equity capital structure and a cost of debt of 6.0%, the recommended 8.5% overall after-tax cost of capital implies a 12.6% return on equity (or realized internal rate of return on the equity portion of the investment) and a weighted average cost of capital of 9.3% (without accounting for the tax advantage of debt). At 65% debt financing and a 6.5% cost of debt, the implied return on equity is 15.5%, yielding a weighted average cost of capital of 9.7%. The cost of debt in these recommendations significantly exceeds the actual (shorter-term) cost of debt reflected in the outstanding bonds on the sample companies' current balance sheets. This reflects the higher risks of merchant generation investments in Alberta's proposed capacity market, and incorporates the possibility that some of the new plants may be developed under a project financing framework rather than solely using balance-sheet-financing arrangements.

Table ES-1 below shows the CONE estimates for the three reference technologies. We calculate the first year annualized costs for the plants assuming a long-term cost recovery path in which total net revenues remain constant in nominal terms (often referred to as the "level-nominal" approach). The CONE estimate is highest for the Aero CT at a value of $244.2/kW-year, expressed in terms of installed capacity (ICAP). Though the Frame CT has only marginally higher overnight capital costs than the Aero CT, its CONE value is much lower at $114.1/kW-year, reflecting its much larger capacity. The CC is the largest unit and has the highest overnight capital costs, yielding a CONE value of $236.1/kW-year, which is slightly lower than the CONE value derived for the Aero CT. These estimates reflect our final cost assumptions as developed and refined with several rounds of input received from AESO stakeholders.[1]

Table ES-1: Estimated CONE for 2021/2022 Delivery Year (2021 CAD)

Reference Technology	Winter Capacity	Overnight Capital Costs	Overnight Capital Costs	Overall (After-Tax) Cost of Capital	Annual Carrying Charge	Plant Capital Costs	Fixed O&M Costs	Gross CONE
	MW	*$million*	*$/kW*	*%*	*%*	*$/kW-yr ICAP*	*$/kW-yr ICAP*	*$/kW-yr ICAP*
Aeroderivative CT	93	$138	$1,479	8.5%	12.6%	$186.9	$57.3	$244.2
Frame CT	243	$163	$671	8.5%	12.7%	$85.0	$29.2	$114.1
Combined Cycle	479	$657	$1,371	8.5%	13.3%	$182.2	$53.9	$236.1

Sources and notes:
CONE values are expressed in 2021 dollars and Installed Capacity (ICAP) terms. Overnight capital costs are in nominal dollars. The annual carrying charge accounts for the cost recovery path, financing, depreciation, and taxes and is derived by dividing plant capital costs ($/kW-yr) by overnight capital costs ($/kW)..

Looking beyond the initial 2021/2022 delivery year, we recommend that AESO update the CONE estimates prior to each subsequent capacity auction using a composite cost index composed of indices that reflect changes over time to the underlying turbine, materials, and labor costs. We recommend the AESO use indices reported by Statistics Canada for escalating labor and materials costs. Specifically, we recommend that labor costs track the Construction Union Wage Rate Index for electricians in Edmonton and materials track the Canadian gross domestic product (GDP) price deflator. As our plant capital cost estimates assume the combustion turbines are sourced from the United States, we recommend that turbine costs track

[1] We presented to stakeholders a summary of our approach, initial results, responses to their feedback, and updated results reflecting their feedback during four Demand Curve Working Group (DCWG) meetings from April to August 2018. The materials presented at the meetings are available at https://www.aeso.ca/market/capacity-market-transition/comprehensive-market-design/demand-curve-working-group/.

the Producer Price Index for turbines and turbine generator sets reported by the U.S. Department of Labor Bureau of Labor Statistics, with an adjustment for changes in the U.S./Canadian exchange rate. Consistent with the capital cost estimates and the relative contribution to total costs of each component category, we recommend that AESO weight the component indices in the Aero CT composite index based on 25% labor, 40% turbine, and 35% materials and other equipment. We recommend that AESO weight the component indices for the Frame CT based on 25% labor, 30% turbine, and 45% materials and other equipment. For the CC, we recommend that AESO weight the components based on 35% labor, 15% turbine, and 50% materials and other equipment.

I. Introduction

A. Background

AESO developed a Comprehensive Market Design (CMD) for the Alberta wholesale electricity market that includes the introduction of a centralized three-year-forward capacity market to be implemented for a first commitment period starting at the end of 2021.[2] The proposed capacity market design utilizes an administratively-determined sloped demand curve to procure sufficient capacity to achieve the resource adequacy standard set by the Government of Alberta and to limit the volatility of prices in the capacity market. A key input to setting the demand curve is the Cost of New Entry (CONE), which represents the long-run marginal cost of supply for achieving AESO resource adequacy objectives.

CONE is calculated as the total annual net revenue (net of variable operating costs) that an economically-efficient new generation resource would need to earn in the Alberta wholesale market to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. CONE is the starting point for estimating the Net Cost of New Entry (Net CONE). Net CONE represents the annual revenues that a new resource would need to earn in the capacity market, after netting out energy and ancillary service (E&AS) margins from CONE. CONE and Net CONE are used to "anchor" the AESO's administratively-set demand curve, such that prices will rise to near the administratively-determined Net CONE when the market is in equilibrium.

The value AESO selects for Net CONE will neither determine nor predict the capacity market clearing price in any given auction. Rather, the market clearing price will depend both on the offers that suppliers make into the capacity market auction as well as on the shape of the demand curve. Net CONE will, however, play an important role in ensuring that the Alberta capacity market procures sufficient capacity on average: if Net CONE is set too high, the capacity market will over procure capacity; if set too low, the market will under procure and possibly not achieve its reliability objectives. Therefore, to cost effectively meet the reliability objectives of the capacity market, the demand curve's Net CONE parameter should accurately estimate the price at which developers of new generation resources would actually be willing to enter the capacity market.

As currently proposed in the CMD Final package, the AESO will update the estimated CONE values during demand curve review cycles every four to five years based on bottom-up cost

2 The AESO is implementing an initial transition period from November 2019 through October 2021. The first three base auctions during the transition have forward commitment periods shorter than three years of 16–28 months. Starting with the base auction in October 2021, all base auctions will be conducted a full three years prior to the start of the obligation period. See AESO (2018). CMD Final Proposal, Section 5: Base Auction, p. 1, available at https://www.aeso.ca/assets/Uploads/CMD-4.0-Section-5-Base-Auctions-FINAL.pdf.

estimates and financing assumptions developed by an independent consultant.[3] In the periods between review cycles, the AESO will update the CONE values prior to each base capacity auction based on applicable cost indices.

B. Scope and Objective

To estimate the CONE value for the Alberta capacity market demand curve, AESO requested that Brattle and S&L complete the following tasks:

- Review potential candidate technologies for the reference technology based on Alberta-specific market conditions and resources that recently entered the market and recommend three technologies for developing CONE estimates.
- Develop detailed technical specifications for the three chosen reference technologies, including machine type and model, configuration, fuel supply, and environmental controls, and identify a location in Alberta that is representative of future development.
- Develop a bottom-up plant capital cost and operations and maintenance (O&M) cost estimates for each technology based on the detailed specifications and location assuming a November 1, 2021 online date.[4]
- Determine an appropriate discount rate, economic life, and levelization approach to convert the estimated costs into the total annualized net revenues necessary to enter the market (CONE).
- Propose methods for updating the CONE value in the periods between demand curve review cycles.

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3 AESO (2018). CMD Final Proposal, Section 4: Calculation of Demand Curve Parameters, available at https://www.aeso.ca/assets/Uploads/CMD-4.0-Section-4-Calc-of-Demand-Curve-FINAL.pdf.

4 The assumptions and costs underlying our CONE estimates reflect a three-year forward commitment period in accordance with CMD Final. During the auction phase-in period, the time between the capacity auction and the start of the commitment period will be less than three years. While some types of capacity resources (such as demand response, upgrades to existing units, or imports) will have lead times of less than three years, we recognize that new generation resources, which under normal circumstances require a 20–36 month construction period, may need to start construction prior to the auction or be built under an accelerated schedule (assuming such new resources actually cleared the market). In this study, we develop CONE values that reflect a normal plant development schedule. We do so because it is our understanding that while the market transitions to the full three-year forward period AESO aims to provide stability to the demand curve and the capacity auctions by maintaining a consistent approach to calculating the capacity market parameters, including the CONE value. If new resources were to bid in at somewhat higher price to reflect added cost of an accelerated schedule, the initial auctions may clear at these higher prices should those resources be needed.

The AESO will estimate the expected E&AS margins and use the CONE values to calculate Net CONE. Finally, AESO will determine the particular reference technology and its associated Net CONE value to be used in anchoring the capacity auction's sloped demand curve.

Our objective in estimating CONE is to reflect the technology, location, and costs that a competitive developer of new generation facilities will likely be able to realize in the Alberta electricity market, including the proposed capacity market. While every developer of merchant generation resources in a competitive market will seek out low-cost opportunities for new facilities, we aim to capture the types of resources, specifications, and costs that are likely to be widely available to ensure that the CONE value is just high enough to cost effectively attract new entry when necessary.

In this report, we provide relevant research and empirical analysis to inform our recommendations, but recognize where judgments have to be made in specifying the reference resource characteristics and translating its estimated costs into levelized revenue requirements. In such cases, we discuss the tradeoffs and provide our own recommendations.

During our analysis, we presented our initial analysis and draft results to stakeholders at four Technical Working Group meetings.[5] Stakeholders provided comments and questions at the meetings and further information after the meetings, all of which we reviewed. Their input is included in the proposed CONE or is addressed in the report.

C. Analytical Approach

Our starting point for estimating CONE is a characterization of the CC and CT plants in Alberta to reflect the technologies, plant configurations, detailed specifications, and locations where developers are most likely to build. We review the most recent gas-fired generation projects in Alberta and across Canada to determine the set of reference technologies and the key configuration variables defined for each. Important elements include the number of gas and steam turbines, duct firing and power augmentation, cooling systems, emissions controls, and the plant's approach to securing fuel supply.

We identified specific plant characteristics based on: (1) our analysis of the predominant practices of recently-developed plants; (2) our analysis of technologies, regulations, and infrastructure; and (3) our experience from previous CONE analyses. We selected key site

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[5] We presented our approach and preliminary results to stakeholders at four Demand Curve Working Group (DCWG) meetings held from April to August 2018. We presented our approach, screening analysis, draft specifications, and draft cost of capital analysis at DCWG Session 2 on April 6, 2018, a response to stakeholders on the cost of capital at the DCWG Session 3 on May 4, 2018, draft CONE results at the DCWG Session 4 on June 14, 2018, and updated CONE results in response to stakeholder feedback at the DCWG Session 5 on August 16, 2018. The materials presented at the meetings are available at https://www.aeso.ca/market/capacity-market-transition/comprehensive-market-design/demand-curve-working-group/.

characteristics, which include proximity to high voltage transmission infrastructure and major gas pipelines, siting attractiveness as indicated by units recently built or currently under construction, and availability of vacant industrial land. Our analysis for selecting plant characteristics and locations is presented in Section III of this report.

We developed comprehensive, bottom-up estimates of the costs of building and maintaining each reference technology. Sargent & Lundy (S&L) estimated plant proper capital costs—equipment, materials, labor, and the engineering, procurement, and construction (EPC) contracting costs—based on a complete plant design and S&L's proprietary database on actual projects. S&L and Brattle then estimated the owner's capital costs, including owner-furnished equipment, gas and electric interconnection, development and startup costs, land, inventories, and financing fees using S&L's proprietary data and additional analysis of each component. The results of this analysis, including adjustments to initial estimates made based on stakeholder feedback, are presented in Section IV.

We further estimated annual fixed and variable O&M costs, including labor, materials, property tax, firm gas transportation service, insurance, asset management costs, and working capital. The results of this analysis are presented in Section V.

Next, we translated the total up-front capital costs and other fixed-cost recovery of the plant into an annualized estimate of fixed plant costs, which is the Cost of New Entry, or CONE. CONE depends on the estimated capital investment and fixed going-forward costs of the plant as well as the estimated financing costs (cost of capital, consistent with the project's risk) and the assumed economic life of the asset. The annual CONE value for the first delivery year depends on our assumption concerning the expected cost recovery path for the plant, which reflects whether a plant built today can be expected to earn as much in later years as in earlier years. We present in Section VI our financial assumptions for converting the costs of building and operating the plant into an annualized CONE estimate and then present the CONE estimates in Section VII of this report.

The Brattle and S&L authors collaborated on completing this study and report, considering stakeholder input throughout the effort. The specification of plant characteristics was jointly developed, with S&L taking primary responsibility for developing the plant proper capital costs and plant O&M and major maintenance costs, and with the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

II. Technology Screening Analysis

The Alberta wholesale electricity market includes a diverse set of internal resources that can generate during tight supply periods to maintain system reliability. However, the capacity market demand curve needs to reflect the costs for those technologies that are likely to enter the market going forward to ensure that Alberta can meet its reliability requirements over the long-term. In addition, there must be sufficient cost information for each of the technologies to accurately estimate Net CONE.

We screened out several technologies as candidate reference technologies, including coal-to-gas conversions, cogeneration resources, demand-side resources, renewables, and energy storage for the reasons described below. By excluding these resources, we are not making any definitive statements on their viability or expectations for future market entry, but find that they are not appropriate reference technologies at this time for setting the demand curve CONE and Net CONE parameters.

- *Cogeneration and Coal-to-Gas Conversions*: While there is significant capacity in Alberta for both of these types of resources, the costs of building and operating cogeneration and coal-to-gas resources are unique to each project and would increase the risk of developing an inaccurate CONE value. In addition, there are inherent constraints in developing future capacity since cogeneration units are co-located with large, industrial loads, and coal-to-gas conversions are limited to the number and size of existing coal plants.
- *Renewable technologies* (including wind and solar resources) are screened out because they are not dispatchable resources that system operators can call upon to meet system demand when capacity is scarce. In addition, renewable resources are not built in Alberta to maintain resource adequacy but instead are installed primarily to meet policy objectives concerning greenhouse gas (GHG) emissions.
- Although *energy storage* resources, such as lithium-ion battery storage, are not a generation resource, they can provide reliable supply for limited durations during supply shortage events and may play an important role in meeting resource adequacy targets in a future with increasing renewables. Energy storage resources at this time though have not been deployed or proposed at sufficient scale in Alberta. If, in the future, energy storage resources are being proposed and constructed in Alberta on a merchant basis, they should be considered as a potential reference technology.
- *Demand-side resources*, such as demand response and energy efficiency, were screened out due to the difficulties of identifying and specifying a standard demand-side resource that could be used for a bottom-up cost estimate. Demand resources are not standardized because their characteristics depend on the type of load they are intended to curtail during peak load periods. Demand-side resources also face inherent constraints on providing the marginal capacity necessary to meet resource adequacy requirements over the long term.

The remaining resources that we considered in our screening analysis are the four gas-fired technologies shown in Table 1 below: Aero CT, Frame CT, CC, and reciprocating internal combustion engines (RICE). For each resource, we reviewed their typical capacity, recent installations, capital cost range, efficiency, and speed of deployment.

Table 1: Candidate Reference Technologies Screening Considerations

Technology	Typical Capacity (MW)	Alberta Installations (Planned) since 2008 (MW)	Indicative Plant Capital Costs (CAD/kW)	Efficiency (kJ/kWh, HHV)	Speed of Deployment (months)	Primary Considerations for Including in Cost Estimates	Include as Candidate Technology?
Aero CT	45–115	483 (664)	$1,300–2,000	9,200–9,600	20 months	Most frequently built technology	✓
Frame CT	90–370	85 (692)	$700–1,850	9,500–11,900	20 months	Significant planned capacity; lowest capital cost	✓
CC	140–850	851 (1,920)	$1,200–1,700	6,500–7,800	36 months	Most recently installed and planned capacity	✓
Reciprocating Engine (RICE)	30–110	112 (94)	$1,450-1,900	8,800	20 months	Limited planned capacity despite low heat rate and similar capital costs	

Sources and notes:
Data downloaded from ABB Inc.'s Energy Velocity Suite and S&P Global in February 2018, cross referenced with AESO LTA reports. Plant costs shown in this table are high-level estimates intended for screening purposes only.

Following a review of these factors, we chose to include the Aero CT, Frame CT, and CC but not the RICE resource as a candidate reference technology. We screened out the RICE primarily due to the small scale of planned development of this resource despite its similarity in efficiency and cost to the much more prevalent Aero CT.[6] Installation of RICE units have increased over the past few years in other Canadian and U.S. markets, but primarily in markets with higher levels of renewable capacity, such as the Southwest Power Pool, ERCOT, and MISO. While few frame CT technologies have been installed in Alberta to date, we include this generation type due to its low cost and significant planned development.

[6] We discussed developing CONE values for a RICE resource as a fourth reference technology with AESO and its stakeholders via the DCWG. Following the April 2018 DCWG meeting, the AESO gauged stakeholders on their interest for including RICE resources as a candidate reference technology and ultimately determined to not do so in this CONE study.

III. Technical Specifications of Reference Technologies

We determined the technical specifications of each candidate reference technology primarily using a "revealed preferences" approach in which we consider the choices that developers have recently found to be most feasible and economic, as observed in recently constructed and planned units in Alberta. However, because technologies and environmental regulations continue to evolve, we supplemented the observations based on our expertise and additional analysis of underlying economics, regulations, and infrastructure.

A. Locational Screen

We conducted a locational screening analysis to select a favorable and feasible location for a new merchant power plant in Alberta. Specifying a single location is necessary for developing accurate performance characteristics of the reference technologies and estimating cost components, such as labor costs, land costs, property taxes, and gas and electrical interconnection costs.

We chose the greater Edmonton region as the location for the reference technologies. Our approach for identifying this location included six factors of consideration.

First, we identified candidate locations based on the revealed preference of gas-fired plants built since 2008 or under development as of the time of this study.[7] Using this criterion, we narrowed the choice to either the Edmonton or Calgary areas. Figure 1 below shows the areas around Edmonton and Calgary that have several operating and permitted gas-fired facilities as well as substantial electrical transmission and gas pipeline infrastructure. We did not consider the regions in the eastern and northeastern portion of the province despite the significant recent development in these areas since the resources added there are primarily cogeneration facilities at oil sands production sites.

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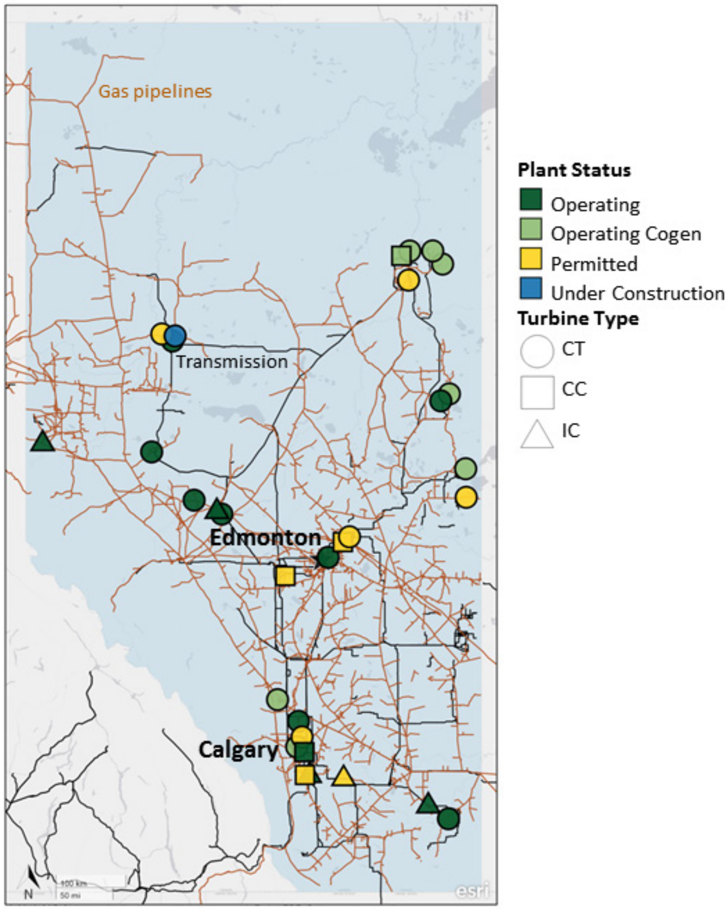
7 We included under development plants that have been at least permitted in our locational review.

Figure 1: Permitted and Operating Gas-Fired Units Built since 2008



Sources and notes:
S&P Global Market Intelligence, as generated July 19, 2018.

To distinguish between Calgary and Edmonton, we considered five more factors including the ease of gas and electric interconnection, labor costs, water permit availability, transmission loss factors, and ambient conditions. Among these criteria, we found that the ambient conditions and the water availability were the biggest differentiating factors. Edmonton is located at a lower elevation than Calgary, which can have a significant impact on net plant capacity for gas-fired resources.[8] We received feedback from AESO and stakeholders that water permits are likely unavailable in Calgary, making it infeasible to use water for cooling a power plant there. The other factors were not materially different between Edmonton and Calgary.

We calculate the plant operating characteristics (*e.g.*, net capacity and heat rate) of the reference technologies using turbine vendors' performance estimation software for the combustion turbines output and GateCycle software for the remainder of the CC plant. For the reference Edmonton location, we estimate the performance characteristics at a representative elevation and

8 Elevation in Calgary is roughly 400 meters higher than in Edmonton. A 400 meter increase in elevation would reduce net summer output by approximately 4%.

at a temperature and humidity that reflects peak conditions. S&L sourced and averaged temperature data from multiple weather stations in the reference Edmonton location, as made publicly available by ASHRAE (the American Society of Heating, Refrigerating, and Air-Conditioning Engineers).[9] Table 2 summarizes the ambient conditions assumed for the Edmonton reference location.

Table 2: Assumed Edmonton Ambient Conditions

Criteria	*Unit*	Value
Elevation	*m*	760
Winter		
Temperature	*°C*	-27.0
Relative Humidity	*%RH*	80.0
Summer		
Temperature	*°C*	25.8
Relative Humidity	*%RH*	41.4
Average Annual		
Temperature	*°C*	3.8
Relative Humidity	*%RH*	60.0

Sources and notes:
Humidity and temperature data from The American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE). Weather stations used are Tomahawk AGDM, AB, Canada; Highvale, AB, Canada; and Edmonton Stony Plain CS, AB, Canada. Elevation data from Alberta Environment and Parks (AEP).

B. Reference Technology Specifications

Based on the assumptions discussed below, the technical specifications for the Aero CT, Frame CT, and CC reference technologies are shown below in Table 3, Table 4, and Table 5. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 2.[10]

9 The 1% cooling dry bulb temperature reported by ASHRAE is used for the summer condition for the reference technologies, and the 99% heating dry bulb temperature reported by ASHRAE is used for the winter design condition.

10 The net plant heat rates presented in Table 3, Table 4, and Table 5 account for balance of plant loads, other plant auxiliary loads, and losses of the generator step-up (GSU) transformer. Grid connection losses are not included, as performance test measurement points are typically at the high side terminal of the GSU transformer. Also, the grid connection losses are expected to be insignificant compared to the GSU transformer losses.

Table 3: Aero CT Reference Resource Technical Specifications

Plant Characteristic	Aeroderivative CT
Turbine Model	GE LM6000-PF SPRINT
Configuration	2 x 0
Power Augmentation	None
Net Plant Capacity	
Max Winter (MW)	93
Max Summer (MW)	78
Annual Average (MW)	87
Net Plant Heat Rate	
Max Winter (kJ/kWh, HHV)	9,526
Max Summer (kJ/kWh, HHV)	9,954
Annual Average (kJ/kWh, HHV)	9,677
Emissions Rate	
(Tonnes CO2/MWh)	0.50
Environmental Controls	Dry low NOx burners
Dual Fuel Capability	No
Firm Gas Contract	Yes
Black Start Capability	None
On-Site Gas Compression	None
Assumed Forced Outage Rate	2.5%

Sources and notes:
See Table 2 for ambient conditions assumed for calculating net summer and winter installed capacities (ICAP) and net summer and winter heat rates.

Table 4: Frame CT Reference Resource Technical Specifications

Plant Characteristic	Frame CT
Turbine Model	Siemens SGT6-5000F
Configuration	1 x 0
Power Augmentation	None
Net Plant Capacity	
Max Winter (MW)	243
Max Summer (MW)	226
Annual Average (MW)	240
Net Plant Heat Rate	
Max Winter (kJ/kWh, HHV)	10,109
Max Summer (kJ/kWh, HHV)	10,317
Annual Average (kJ/kWh, HHV)	10,061
Emissions Rate	
(Tonnes CO2/MWh)	0.52
Environmental Controls	Dry low NOx burners
Dual Fuel Capability	No
Firm Gas Contract	Yes
Black Start Capability	None
On-Site Gas Compression	None
Assumed Forced Outage Rate	2.5%

Sources and notes:
See Table 2 for ambient conditions assumed for calculating net summer and winter installed capacities (ICAP) and net summer and winter heat rates.

Table 5: Combined Cycle Reference Resource Technical Specifications

Plant Characteristic	Combined Cycle
Turbine Model	Siemens SGT6-8000H
Configuration	1 x 1
Cooling System	Wet Cooling
Power Augmentation	None
Net Plant Capacity, without Duct Firing	
Max Winter (MW)	429
Max Summer (MW)	389
Annual Average (MW)	421
Net Plant Capacity, with Duct Firing	
Max Winter (MW)	479
Max Summer (MW)	438
Annual Average (MW)	471
Net Plant Heat Rate, without Duct Firing	
Max Winter (kJ/kWh, HHV)	6,981
Max Summer (kJ/kWh, HHV)	6,811
Annual Average (kJ/kWh, HHV)	6,814
Net Plant Heat Rate, with Duct Firing	
Max Winter (kJ/kWh, HHV)	7,163
Max Summer (kJ/kWh, HHV)	7,047
Annual Average (kJ/kWh, HHV)	7,026
Emissions Rate	
Without Duct Firing (Tonnes CO2/MWh)	0.34
With Duct Firing (Tonnes CO2/MWh)	0.35
Environmental Controls	Dry low NOx burners and SCR
Dual Fuel Capability	No
Firm Gas Contract	Yes
Black Start Capability	None
On-Site Gas Compression	None
Assumed Forced Outage Rate	2.5%

Sources and notes:
See Table 2 for ambient conditions assumed for calculating net summer and winter installed capacities (ICAP) and net summer and winter heat rates.

1. Turbine Model and Configuration

We reviewed the most recently built or permitted gas-fired generation projects in Alberta to determine the configuration, size, and turbine types for the reference resources. Table 6 below shows that aeroderivative CTs are the most frequently built gas combustion turbine technology in Alberta. We specified the Aero CT to include the GE LM6000 turbine because it is the most built turbine type in total capacity and in number of units. Due to the significant reduction in net plant capacity of LM6000 turbines at summer temperatures, we evaluated the costs and incremental capacity of three different power augmentation options: spray-intercooling technology (referred to as SPRINT turbines) or evaporative cooling or both.[11] We found that the turbine with SPRINT technology alone offered the most benefit (a 12 MW increase under summer conditions) for relatively low additional costs ($3 million CAD).[12] A detailed summary of the power augmentation configurations is provided in Appendix A.

Table 6: Turbine Models of CT Plants Built Since 2008 or Planned in Alberta

Turbine Model	Turbine Type	Capacity Installed and Permitted since 2008 *MW*	Number Installed and Permitted since 2008 *Count*
GE LM6000	Aeroderivative CT	719	15
Siemens SGT6-5000F	Frame CT	600	3
GE LMS100	Aeroderivative CT	200	2
Rolls-Royce Trent 60	Aeroderivative CT	198	3
GE 7EA	Frame CT	177	2
Wartsila 18V50SG	Reciprocating	94	5
Caterpillar-G16CM34	Reciprocating	65	10
Solar Turbines Inc-Titan 130	Aeroderivative CT	30	2
Cummins C2000 N6C	Reciprocating	20	10
Jenbacher JGS 620	Reciprocating	18	6
Wartsila 20V34SG	Reciprocating	9	1
Total		**2,130**	**59**

Sources and notes:
Downloaded from ABB Inc.'s Energy Velocity Suite February 2018. Table does not contain units designated as cogeneration facilities. CTs shown only for simple-cycle configurations, not combined-cycle.

Because most aeroderivative CT plants in Alberta include multiple turbines, we specified two LM6000 turbines ("2×0 configuration").

For the simple-cycle Frame CT, we considered three different sized turbines, commonly referred to as E-class (about 100 MW per turbine), F-class (about 240 MW per turbine), and H-class (about 370 MW per turbine) turbines. There are very few standalone simple-cycle Frame units in Alberta (most Frame turbines operate in cogeneration facilities), so we considered both representative units in Alberta and S&L's recent experience with developers considering Frame units. We first eliminated the H-class turbine because there are no existing or planned simple-

11 GE SPRINT technology uses atomized water injection to both compress and increase mass flow through the CT, resulting in increased output. Evaporative cooling provides cooling of the inlet air by means of water evaporation from a media surface located upstream of the compressor, resulting in increased output.

12 Based on discussion with a GE vendor, developers in Alberta are showing substantial interest in the SPRINT technology, with approximately half of LM6000 quotes including SPRINT technology.

cycle H-class turbines in the Alberta market, and it is much larger than existing CTs. There has been limited recent development of the either the E- or F-class turbines, but we found that the F-class has both lower capital costs and better efficiency than the E-class.[13] Therefore, the F-class turbine was the best choice for the Frame CT reference technology.

We used a similar methodology for selecting the CC turbines and configuration. There is only one operating CC in Alberta built in the last decade, which was built with two Mitsubishi G-class turbines and a single heat recovery steam generator (HRSG) and steam turbine ("2×1 configuration"). Looking forward, four CCs are currently being developed in Alberta, all in 1×1 configurations with three using the larger J/H-class turbines and one using the Siemens F-class turbine. Based on these recently built and proposed CCs, we specified the reference CC to include a single H-class turbine (the Siemens SGT6-8000H) in a 1×1 configuration.

Table 7: Recently Built and Planned Combined Cycle Units in Alberta

Plant	Unit Status	Turbine Model	Configuration	Capacity *MW*
Shepard Energy Centre	Operating	Mitsubishi M501G1	2x1	851
Genesee (CAN)	Permitted	Mitsubishi 501J	1x1	530
Genesee (CAN)	Permitted	Mitsubishi 501J	1x1	530
Heartland Generating Station	Permitted	Siemens SGT6-8000H	1x1	510
Saddlebrook Power Station	Permitted	Siemens SGT6-5000F	1x1	350

Sources and notes:
Downloaded from ABB Inc.'s Energy Velocity Suite February 2018.

Additionally, we include supplemental firing of the steam generator, known as "duct firing," which increases steam production and hence increases the output of the steam turbine.[14] Duct firing is common, although there is no standard optimized design. The decision to incorporate supplemental firing with the plant configuration and the amount of firing depends on the owner's preference and perceived economic value. We assumed the reference CC plant would add duct firing sufficient to increase the net plant capacity by 50 MW (13%) based on our understanding of duct-firing capabilities at existing CCs in Alberta.

13 The Carmon Creek site has three planned F-class CT turbines, but this facility is a special case. The Carmon Creek site was partially developed by Shell as a cogeneration plant to access oil sands. Kineticor plans to finish the project and repurpose the facility as a standalone power plant composed of the three F-class Frame CTs.

14 Including duct firing increases the net capacity of the plant but reduces efficiency due to the higher incremental heat rate of the supplemental firing (when operating in duct-firing mode) and the reduced efficiency of steam turbine (when not operating at full output). The estimated heat rates and capacities take account for this effect.

2. Environmental Requirements and Implications

Alberta Environment and Parks (AEP) sets power plants emissions standards in Alberta.[15] The current regulations concerning nitrogen oxides (NOx) emissions were last updated in 2005 and require that the reference technologies install dry low NOx burners to meet the NOx emissions standards. Based on conversations with AEP staff, we are aware that the AEP is in the process of updating the standards and is evaluating the costs and performance of selective catalytic reduction (SCR) systems. However, the AEP has not provided any indication as to whether the new standards will require gas-fired technologies to install SCRs. Recent CCs proposed in Alberta have included plans to install SCRs, likely in an attempt to minimize community opposition and project delays related to permitting and in anticipation of future NOx regulation. Consequently, we assume a new CC would include an SCR even though it is not strictly required at the time of this study. Given the lack of technology mandates or recent simple-cycle CT builds with SCRs, we do not specify an SCR on the simple-cycle reference technologies.[16]

Canada has a national source standard of 50 ppm for carbon monoxide (CO), which was established in 1992.[17] This standard is not binding for the reference technologies. Thus, we have not included oxidation catalysts for any of the three technologies.

The Canadian government updated the federal carbon dioxide (CO_2) emissions regulations on natural-gas fired generation over 25 MW in early 2018.[18] The updated CO_2 emissions rate limits apply only to units with a capacity factor greater than 33% and vary by unit size, with units larger than 150 MW limited to 0.42 tonnes/MWh and units between 25 MW and 150 MW limited to 0.55 tonnes/MWh. The emissions rate of new CCs are sufficiently low to meet the 0.42 tonnes/MWh limit for larger units, and the same is true for the Aero CTs at the less restrictive rate applied to smaller units.[19] The less efficient Frame CT, however, will exceed the 0.42 tonnes/MWh limit and thus will be restricted to a 33% capacity factor.[20]

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15 Alberta Environment and Parks (2005). Alberta Air Emission Standards for Electricity Generation and Alberta Air Emission Guidelines for Electricity Generation, available at http://aep.alberta.ca/air/legislation-and-policy/documents/AirEmissionStandardsGuidelinesElectricity.pdf.

16 At a high-level, adding SCRs to the simple-cycle technologies, including additional labor costs, would increase nominal overnight costs for the Aero CT and Frame CT by $147/kW and $28/kW, respectively. This would translate to an increase in CONE of $18/kW-yr (2021, CAD) for the Aero CT and $3/kW-yr for the Frame CT.

17 Government of Canada (1992). National Emissions Guidelines for Stationary Combustion Turbines, available at https://www.ccme.ca/files/Resources/air/emissions/pn_1072_e.pdf.

18 Government of Canada (2018). Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity, *Canada Gazette* 152(7), available at http://gazette.gc.ca/rp-pr/p1/2018/2018-02-17/html/reg4-eng.html.

19 Assuming a CO_2 emissions rate for natural gas of 0.050 tonnes/GJ and using the net summer heat rates presented in Table 5, the reference CC's CO_2 emissions rates will be approximately 0.35 tonnes/MWh

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3. Fuel Supply Specifications

Despite the abundance of natural gas in Alberta, the recent shift in natural gas production to the northwest portion of the province and existing long-term export arrangements have resulted in a demand-constrained natural gas pipeline system across most of the province.[21] To ensure delivery of natural gas to new power plants, we assume developers will enter into firm transportation service contracts with Nova Gas Transmission Ltd. (NGTL), which owns and/or operates the predominant natural gas transportation system in Alberta. Though it may be possible for some developers to make fuel supply arrangements directly to a natural gas processing facility and bypass the NGTL system, these projects are not likely to be the norm.[22]

An alternative approach to securing fuel supply is to install "dual-fuel" capability, which allows the plant to burn both gas and diesel fuel. Dual-fuel plants permit the turbines to switch between the lower cost fuel sources depending on market conditions and fuel availability. Given the demand constraints facing Alberta's pipeline system and the need for firm transportation service, developers are not likely to include dual-fuel capabilities and have not chosen to do so for recent gas-fired generation projects.[23]

4. Additional Specifications

Combined Cycle Cooling System: For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell mechanical draft cooling tower based on the predominance of cooling towers among new CCs and S&L's experience in Alberta. An alternative to the wet cooling system is an air-cooled system. Air cooling is substantially more expensive, but wet cooling requires access to water and the ability to obtain the necessary permits. We believe that competitive developers will pursue wet cooling, in the interest of project economics, as long as water resources are available. Though water availability is

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and 0.34 tonnes/MWh with and without duct firing, respectively. Based on the net summer heat rates presented in Table 3, the Aero CT's emission rate will be approximately 0.50 tonnes/MWh. See U.S. Environmental Protection Agency, Greenhouse Gases Equivalences Calculator—Calculations and References, available at https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references.

20 Assuming a CO_2 emissions rate for natural gas of 0.050 tonnes/GJ and using the net summer heat rate presented in Table 4, the Frame CT's CO_2 emissions rate will be approximately 0.52 tonnes/MWh. *Id.*

21 TransCanada's NGTL System FT-D Availability Map as of June 8, 2018, available at http://www.tccustomerexpress.com/docs/Delivery%20Map%20June%208%202018.pdf.

22 Additionally, natural gas plants are very sensitive to the sulfur content of the gas, which is carefully monitored by NGTL and may not be by independent suppliers. This incorporates additional operational risks, which would need to be included in the cost estimates.

23 Determined through review of data downloaded from ABB Inc.'s Energy Velocity Suite in February 2018.

constrained in much of Alberta, it is our understanding that AEP is still accepting water license applications for water usage from the North Saskatchewan River Basin. Information published by AEP indicates that only 20% to 30% of the usable capacity from the North Saskatchewan River has been allocated.[24] A CC plant built near Edmonton would be pulling water from the North Saskatchewan River, thus it is feasible to obtain water permits in the Edmonton area.

Black Start Capability: We did not include black start capability in any of the reference units.

Electric Interconnection: We selected 240 kV as the typical voltage for a new CC plant and 115 kV for the Aero and Frame CTs to interconnect to the AESO's transmission grid. The switchyard is assumed to be within the plant boundary and is counted as an EPC cost under "Other Equipment," including generator circuit breakers, main power and auxiliary generator step-up transformers, and switchgear. All other electric interconnection equipment, excluding network upgrades socialized by the AESO, is included separately under Owner's Costs.

Gas Compression: We assume gas compression would not be needed for the reference technologies as they are located near and/or along NGTL's pipeline system. Both the Frame and Aero CT turbines operate at lower gas pressures than the gas pipelines.

24 Government of Alberta Environment (2018). How Water is Governed: Water Licenses, Transfers, and Allocation, available at http://alberta-water.ca/how-is-water-governed/water-licences-transfers-and-allocation. Note that upcoming coal retirements in the Edmonton area may further increase water permit availability.

IV. Plant Capital Cost Estimates

Plant capital costs are those costs incurred when constructing the power plant before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction (EPC) company to complete construction and to ensure the plant operates properly. EPC costs include major equipment, labor, and materials, and non-EPC or owner's costs include development costs, startup costs, interconnection costs, and inventories.

Based on the technical specifications described above, the total capital costs for plants with an online date of November 1, 2021 are shown in Table 8.[25] The methodology and assumptions for developing the capital cost line items are described further below and summarized in Appendix H.

25 The plant capital costs presented herein reflect Class 4 estimates with an accuracy level of + / – 30%.

Table 8: Plant Capital Costs for CT Reference Resource in Nominal Dollars (CAD) for 2021 Online Date

Capital Costs ($million)	Aeroderivative CT 93 MW	Frame CT 243 MW	Combined Cycle 479 MW
Owner Furnished Equipment			
Gas Turbines	$52.7	$47.9	$95.8
SCR	$0.0	$0.0	$30.4
Total Owner Furnished Equipment	**$52.7**	**$47.9**	**$126.2**
EPC Costs			
Equipment	$11.3	$20.0	$77.2
Construction Labor	$21.9	$28.4	$177.4
Other Labor	$7.9	$9.4	$39.3
Materials	$6.6	$8.4	$60.0
EPC Contractor Fee	$6.0	$6.9	$45.4
EPC Contingency	$8.5	$9.7	$50.0
Total EPC Costs	**$62.3**	**$82.8**	**$449.3**
Non-EPC Costs			
Project Development	$5.8	$6.5	$28.8
Mobilization and Start-Up	$1.2	$1.3	$5.8
Net Start-Up Fuel Costs	-$1.3	-$3.2	-$13.6
Electrical Interconnection	$5.7	$14.9	$26.3
Gas Interconnection	$4.2	$4.2	$4.2
Land	$1.0	$1.0	$3.1
Non-Fuel Inventories	$1.7	$2.0	$8.6
Owner's Contingency	$1.5	$2.1	$5.1
Financing Fees	$2.7	$3.2	$12.9
Total Non-EPC Costs	**$22.5**	**$32.1**	**$81.1**
Total Capital Costs	**$137.5**	**$162.8**	**$656.7**
Overnight Capital Costs ($million)	$138	$163	$657
Overnight Capital Costs ($/kW)	$1,479	$671	$1,371
Installed Cost ($/kW)	$1,579	$713	$1,548

A. Plant Proper Capital Costs

1. Plant Developer and Contractor Arrangements

Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, HRSG, condenser, and steam turbine), other equipment, construction and other labor, materials, contractor's fee, and contractor's contingency.

We have assumed a contracting scheme for procuring professional EPC services that is implemented with a single contractor at a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting scheme.

We recognize that not all developers of new generation facilities in Alberta will choose this approach, especially incumbent generators with significant in-house experience developing new projects in the province. However, we find that assuming an EPC contract will properly price into the cost estimates the value that developers place on shifting the risk of cost and schedule overruns to the EPC firm.

2. Equipment

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines, where applicable. Note that the gas turbines for the CC cost more per turbine than for the CTs because the manufacturer includes additional valves, gas pre-treatment, and other components that are required for CC operation.

The major equipment includes "owner-furnished equipment" (OFE) purchased by the owner through the EPC. OFE costs include EPC handling costs and contingency on logistics, installation, delivery, *etc.*, with no EPC profit markup on the major equipment cost itself. "Other equipment" includes inside-the-fence equipment required for interconnection and other miscellaneous equipment and associated freight costs. Equipment costs, including the combustion turbine costs, are based on S&L's proprietary database and continuous interaction with clients and vendors regarding equipment costs and budget estimates.

Because the major equipment will be manufactured in the United States and shipped to Canada, the costs are initially estimated in U.S. dollars and subsequently converted to Canadian dollars. Payments for major equipment, including combustion turbines for all units and the steam turbine, SCR, heat recovery steam generator (HRSG) and the condenser for the CC, are made in installments over the first year of the construction period, exposing turbine costs for a Canadian project to fluctuations in the U.S./Canadian exchange rate. We anticipate developers would hedge the exchange rate risk. In response to stakeholder input, we have accounted for this in our CONE estimates by applying forward exchange rates in accordance with typical payment schedules that spread the major equipment payments over the first year of the construction schedule.[26,27]

26 The administrative transaction costs associated with the foreign exchange hedging will be *de minimis*; these are not explicitly estimated but assumed to be part of owner's costs. The forward exchange rates were sourced from CME Group, as reported July 6, 2018, available at https://www.cmegroup.com/trading/fx/g10/canadian-dollar_quotes_globex.html.

Based on stakeholder feedback, we exclude from the plant capital cost estimates any sales taxes paid on the equipment. Though the federal government levies a 5% goods and services tax (GST), business can claim an input tax credit (ITC) on goods and services consumed in the process of their commercial activities.[28] Effectively, only the final consumer pays the GST. Alberta does not have a provincial sales tax or a harmonized sales tax (HST).[29]

3. Labor and Materials

Labor consists of "construction labor" associated with the EPC scope of work and "other labor," which includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. "Materials" include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.

The labor rates in this analysis assume that primarily union labor is utilized. While there may be a few non-unionized crafts involved in the construction of the power plants, they are likely to be a relatively small portion of the overall labor force. Labor rates have been developed by S&L through a survey of the prevalent wages in the Edmonton area labor pool in 2018. The labor costs are based on average labor rates weighted by the combination of trades required for each plant type. The labor hours in this analysis are based on S&L experience with similar-sized projects and have been adjusted for the unique conditions and productivity challenges facing construction projects in Alberta. We provide a more detailed discussion of the inputs into the labor cost estimates in Appendix B.

The balance of plant EPC equipment and material costs were estimated using S&L proprietary data, vendor catalogs, and publications. The balance of plant equipment consists of all pumps, fans, tanks, skids, and commodities required for operation of the plant. It includes building enclosures typically observed with projects in Alberta given the extreme weather conditions.

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27 We considered a similar approach for hedging exchange rate risk related to procuring other equipment and materials from the United States. However, most of the balance of plant equipment and materials may be globally sourced, with local sourcing as available, such that there is no obvious basis for assuming which materials and/or equipment would be purchased from the United States and would be exposed to similar exchange rate risk.

28 Based on input tax credits applicable to capital property, we assume any taxes paid under the federal GST would be fully refunded. See the Canada Revenue Agency's discussion of input tax credits, available at https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/gst-hst-businesses/gst-account/input-tax-credits/calculate-input-tax-credits-overview/calculate-input-tax-credits-types-purchases-expenses.html.

29 Certain provinces in Canada have a harmonized sales tax (HST), which combines the federal goods and services tax (GST) with a provincial sales tax.

Estimates for the quantity of material and equipment needed to construct simple- and combined-cycle plants are based on S&L experience on similarly-sized and configured facilities.[30]

4. EPC Contractor Fee and Contingency

The "EPC Contractor's fee" is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. Capital cost estimates include an EPC contractor fee of 6% of total EPC and OFE costs for the Aero CT and Frame CT facilities and 10% for the CC based on S&L's proprietary project cost database.[31] The lower contractor fees associated with the simple-cycle machines reflect the abundance of experience in Alberta with aeroderivative installations and the relatively straightforward installation process for these and similar projects.[32] A higher contractor fee is assigned to the CC given the more complicated nature of developing and constructing a combined cycle plant and the relative lack of CC experience in Alberta. We expect EPC developers to have a competitive edge in CC development, thereby allowing them to charge higher fees.

"Contingency" covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 8% of total EPC and OFE costs for the Aero CT and Frame CT facilities, and 10% for the combined cycle. As with the contractor fees, the higher EPC contingency reflects the more complicated nature of CC installation and the greater likelihood for overlooked or misestimated costs. The lower contingency fee for the simple-cycle facilities reflects the greater risk EPC contractors will likely have to bear for developers to be willing to sign a lump-sum contract for a turn-key facility, instead of taking on that risk themselves.

The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 7.8% to 9.1% of the pre-contingency overnight capital costs.

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30 Some balance of plant equipment and materials are assumed to be sourced from outside of Canada. Unlike the turbines, we assume the balance of plant equipment and materials are globally-sourced from multiple countries. Foreign exchange hedging costs are mitigated through a competitive procurement process. Differences in forward exchange rates across multiple currencies relative to Canadian dollars are assumed to be offset by the relative differences in those currency inflation rates over the construction period. Administrative costs associated with hedging are included in the owner's costs for owner-furnished equipment and in the EPC costs for other equipment.

31 This fee is applied to the Owner-Furnished Equipment to account for the EPC costs associated with the tasks listed above once the equipment is turned over by the Owner to the EPC contractor.

32 Though there is less experience with Frame CT installation in Alberta, a Frame CT installation is similar to that of an aeroderivative CT.

B. OWNER'S CAPITAL COSTS

"Owner's capital costs" include all other capital costs not expected to be included in the EPC contract, including development costs, legal fees, gas and electric interconnections, and inventories.

1. Project Development, Mobilization and Startup

Project development costs include items such as studies, permitting, oversight, and legal fees that are required prior to and generally through the early stages of plant construction. We assume project development costs are 5% of the total EPC and OFE costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.[33]

Mobilization and startup costs include those costs incurred by the owner of the plant towards the completion of the plant and during the initial operation and testing prior to operation, including the training, commissioning, and testing by the staff that will operate the plant going forward. We assume mobilization and startup costs are 1% of the total EPC and OFE costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

2. Net Startup Fuel Costs

Before commencing full commercial operations, new generation plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing and operating the turbine generators on natural gas. S&L estimated the fuel consumption and energy production during testing for each plant type based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. During the startup period, a plant will pay for the natural gas consumption and will receive revenues for its energy production. We estimate the net startup costs using the forward all-hours electricity price as testing can occur throughout the day depending on the commissioning schedule and forward natural gas prices for the months just prior to commercial operation. Due to the high market heat rate in Alberta, we estimate that the plants are likely to earn revenues during this period, which we consider as a credit towards the construction period costs, instead of including them as net revenues in the estimate of the energy and ancillary services offset. We provide additional detail on the calculation of the net startup fuel costs in Appendix C.

3. Gas and Electric Interconnection

We estimated gas interconnection costs based on cost data for gas lateral projects from TransCanada's annual plan. We assume that the gas interconnection will require a 2-kilometer

[33] These projects include the recent LM-6000 gas turbine project in the City of Medicine Hat, Alberta and other projects in Canada and the United States.

lateral built by the EPC contractor and that NGTL will construct the meter station. From the data we summarize in Appendix D, the average gas interconnection cost for projects included in our sample of projects constructed by NGTL is $3.3 million per kilometer, which serves as a starting point for developing the gas interconnection costs. For the purposes of this analysis, we assume the gas lateral will not be built by NGTL, but by a merchant developer as is typical in Alberta. Merchant developers are likely to construct the lateral for a lower cost than NGTL, and thus we assume the gas lateral will cost $2 million per kilometer.[34] We assume the same gas interconnection costs for each of the three facilities.

We estimated electric interconnection costs based on historic and projected electric interconnection cost data provided by the AESO. Electric interconnection costs consist of two categories of "outside the fence" costs: direct connection costs and network upgrade costs.[35] Direct connection costs will be incurred by any new project connecting to the network and include all necessary interconnection equipment such as generator lead and substation upgrades. Network upgrade costs may be incurred when improvements, such as replacing substation transformers, are required. In general, generators are not responsible for network upgrade costs in Alberta, which are socialized by the AESO. Given the Edmonton area location for the reference technologies, we assume no extraordinary network upgrade costs attributable to the generator and estimate and attribute only direct connection costs. Using recent project data on direct connection costs provided by AESO, we calculated a capacity weighted-average of $58/kW (in 2018 dollars) for these projects. The total estimated electric interconnection costs are approximately $8.5 million for the aeroderivative CT, $22 million for the Frame CT, and $41 million for the CC. Appendix D presents additional details on the calculation of electric interconnection costs.

New generation facilities must pay an additional $30/kW to AESO for the generating unit owner's contribution (GUOC) in the Edmonton area when requesting system access service under Rate Supply Transmission Service, which is intended to help pay for the costs of network upgrades.[36] However, the GUOC is refunded over the nine years following the start of commercial operation.[37]

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[34] NGTL identified one project in the publicly-available data we summarize in Appendix D as most representative of the interconnection costs of the reference facilities. This project cost $1.9 million per kilometer and was a consideration in developing the assumed gas interconnection costs.

[35] We consider the switchyard and generation step up (GSU) transformer to be "inside the fence" costs and include those costs in the EPC portion of the cost estimate.

[36] AESO Tariff (2016). Section 10 – Generating Unit Owner's Contribution, available at https://www.aeso.ca/rules-standards-and-tariff/tariff/section-10-generating-unit-owners-contribution/.

[37] The GUOC is paid back in its entirety according to a set schedule. This refund schedule is 5.6% in each of the first through fourth years, 11.2% in the fifth year, and 16.6% in the sixth through ninth years. Based on stakeholder feedback, we have accounted for the GUOC payment and refund in the

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4. Land

We assume that 10 acres of land are needed for aeroderivative and Frame CTs and 30 acres for the CC. We estimated the cost of land to be $104,415 per acre by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in the counties and unincorporated municipal areas surrounding Edmonton (Parkland County, Leduc County, Strathcona County, Sturgeon County, and Fort Saskatchewan).[38] A summary of the land costs are available in Appendix E.

5. Non-Fuel Inventories

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized.[39] We assume non-fuel working capital is 1.5% of EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs. This includes 1.0% for financial working capital and 0.5% for spare parts and consumables.

6. Owner's Contingency

Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, *etc.* We assumed an owner's contingency of 8% of Owner's Costs based on S&L's review of the most recent projects for which it has detailed information on actual owner's costs.

7. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are part of the total capital investment costs, or "installed costs" but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects based on S&L's review of similar projects for which it has detailed information on actual owner's costs. For the purposes of calculating the finances fees, we assume the project is 50% debt-financed and 50% equity-financed (though, as we explain in Section VI.A below, we recognize that some developers may be able to employ more leveraged financing, such as 65% debt).

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CONE estimates. Specifically, the GUOC is incorporated into the NPV analysis of cash flows as a net operating expense in year one and as revenues in the years two through nine.

38 Land costs pulled from Loopnet's Commercial Real Estate Listings (www.loopnet.com) in April 2018.

39 None of the reference technologies have dual-fuel capability so no fuel inventory costs are needed.

C. Escalation to 2021 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period for each technology: 36 months for CCs and 20 months for both the Aero and Frame CTs. As discussed above, this drawdown schedule incorporates typical payment schedules for the turbines and related equipment such that the relevant forward exchange rates can be applied. We escalated the 2018 estimates of overnight capital cost components forward to the construction period for a November 2021 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term (approximately 20-year) historical trends relative to the general inflation rate for gas turbines, other equipment, materials, and labor. The real escalation rate for each cost category was then added to the assumed inflation rate of 2.0% (see Section VI.B) to determine the nominal escalation rates, as shown in Table 9.

Table 9: Capital Cost Escalation Rates

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Turbines	0.0%	2.0%
Equipment and Materials	0.0%	2.0%
Labor	1.2%	3.2%

Sources and notes:
General inflation was measured by the Gross Domestic Product Deflator (GDPD). Real escalation rates for turbines, equipment, and materials were derived from Statistics Canada's Machinery and Equipment Index (MEPI), Industrial Product Price Index (IPPI), Raw Material Price Index (RMPI), and S&L's in-house historical cost data for gas turbines. Real escalation for labor was derived from Statistics Canada's Construction Union Wage Rate Index (CUWRI) and Bank of Canada's Labor Force Survey (LFS).40

To reflect the timing of the costs a developer accrues during the construction period, we escalated most of the capital cost line items from 2018 overnight costs using the monthly capital drawdown schedule developed by S&L for an online date in November 2021.

However, we escalated several cost items in a different manner:

- *Land*: assumed land will be purchased in 2018, prior to the start of construction.
- *Net Start-Up Fuel*: no escalation was needed as we applied forward fuel and electricity prices for 2021.
- *Electric and Gas Interconnection*: assumed the construction of electric interconnection occurs 7 months prior to project completion while gas

40 The updating of the CONE value prior to each base auction would use a weighted combination of the U.S. PPI-Turbine index, adjusted for the CAD/USD exchange rate (for turbines), the GDPD (for materials and other equipment), and the CUWRI index (for labor).

interconnection occurs 8 months prior to completion; the interconnection costs have been escalated specifically to these months.

We used the drawdown schedule to calculate debt and equity costs during construction to arrive at a complete "installed cost." The installed cost for each technology is calculated by applying the monthly construction drawdown schedule for the project to the overnight capital costs, applying escalation rates particular to each cost category, and then finding the present value of the escalated cash flows as of the end of the construction period using the assumed cost of capital as the discount rate. By using the cost of capital to calculate the present value, the installed costs will include both the interest during construction from the debt-financed portion of the project and the cost of equity for the equity-financed portion.

V. Operation and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed O&M costs each year, including property tax, insurance, labor, minor maintenance, and asset management. Annual fixed O&M costs increase the CONE. Separately, we calculated variable O&M costs (including maintenance, consumables, and waste disposal costs) to inform AESO's future E&AS margin calculations. Table 10 summarizes the fixed and variable O&M for plants with an online date of November 1, 2021.

Table 10: O&M Costs for Reference Resources (2021 CAD)

O&M Costs	Aeroderivative CT 93 MW	Frame CT 243 MW	Combined Cycle 479 MW
First Year Fixed O&M ($million)			
LTSA	$0.3	$0.4	$0.5
Labor	$0.9	$0.9	$3.3
Maintenance and Minor Repairs	$0.4	$0.5	$4.6
Administrative and General	$0.2	$0.2	$0.9
Asset Management	$0.1	$0.3	$0.8
Property Taxes	$0.8	$1.0	$4.0
Insurance	$0.8	$1.0	$3.9
Firm Gas Contract	$1.2	$2.2	$4.3
Total First Year Fixed O&M ($million)	**$4.7**	**$6.4**	**$22.3**
Total First Year Fixed O&M ($/kW)	**$50.6**	**$26.6**	**$46.6**
Variable O&M			
Major Maintenance - Hours Based ($/MWh)	$3.9	$0.0	$1.7
Consumables, Waste Disposal, Other VOM ($/MWh)	$0.7	$0.8	$0.9
Total Variable O&M ($/MWh)	**$4.6**	**$0.8**	**$2.7**
Major Maintenance - Starts Based ($/Start)	**$0.0**	**$24,323**	**$0.0**

A. Annual Fixed Operations and Maintenance Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (property taxes and insurance).

1. Plant Operation and Maintenance

We estimated the labor, maintenance and minor repairs, and general and administrative costs based on a variety of sources, including S&L's proprietary database on actual projects, vendor publications for equipment maintenance, and data from Statistics Canada.

Major maintenance is assumed to be completed through a long-term service agreement (LTSA) with the original equipment manufacturer that specifies when to complete the maintenance depending on whether the fired-hours or starts maintenance interval is reached first.[41] Each major maintenance cycle for a combustion turbine typically includes regular combustion inspections, periodic hot gas path inspections, and one major overhaul. We include the costs of long-term maintenance as variable O&M and monthly LTSA payments as fixed O&M.

2. Insurance and Asset Management Costs

We estimated insurance costs as 0.6% of the overnight capital cost per year, based on a sample of independent power projects recently under development in Canada and the U.S.. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of CT and CC plants in operation.

3. Property Tax

To estimate property taxes, we researched tax regulations in the counties surrounding Edmonton. Each county assesses taxes on both land and other property at separate rates. The tax rate applied to land value is the non-residential rate including the education tax; the rate applied to other property is the same, but excludes the education tax. We calculated the average rates across the five counties and applied them to the assessable costs for each reference technology. We reviewed the proper depreciation schedule for each technology, and forecasted the appropriate assessment year modifier and cost factor applicable in 2021. Details of these calculations can be found in Appendix F.

4. Firm Gas Transportation Service Contracts

We estimate the costs of firm gas transportation service contracts based on current NGTL rates and the expected operations of the resources. For developing the size of the transportation service contract, we assume the CC and Aero CT will operate around-the-clock and that the Frame CT will operate only during on-peak hours. Through consultation with NGTL, we developed contracted capacity levels to support these operational assumptions. Based on the Edmonton area location and NGTL requirements, we assume the reference resources must sign initial contracts for firm service with an eight-year term.[42] Following the initial term, we assume

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41 The O&M costs presented in Table 10 above assume the Aero CT and CC trigger major maintenance based on the hours-based interval and the Frame CT does so based on the starts-based interval. The Frame CT maintenance is starts-based due to its relatively low number of operating hours per start compared to the Aero CT and CC. Typical major maintenance intervals are 50,000 fired-hours or 1,440 starts, which yields a ratio of 35 fired-hours per start.

42 The Edmonton vicinity is in a capacity-constrained area of NGTL's system, and additional firm transportation service in this area may require new mainline facilities to be built that command eight-year firm service contracts. Due to the lengthy regulatory process, we understand that firm gas

Continued on next page

the reference resources will continue to renew their firm service contracts given the limited availability and uncertain delivery of interruptible transportation service in Alberta.

We provide detail on the assumptions and calculations for computing the cost of acquiring firm transportation service in Appendix G.

B. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they inform the E&AS revenue offset calculations to be performed by AESO to ensure the calculation of CONE and the E&AS revenue offsets are consistent. Variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, water, and other chemicals and consumables. We assume that the costs related to major maintenance that are often specified in an LTSA are considered variable O&M costs. These costs are primarily related to turbine replacement and refurbished parts.

C. Escalation to 2021 Costs

We escalated the components of the O&M cost estimates from 2018 to 2021 on the basis of cost escalation indices particular to each cost category. The same real escalation rates used to escalate the overnight capital costs in the previous section (see Table 9) have been used to escalate the O&M costs. The assumed *real* escalation rate for labor is 1.2% per year, while other O&M costs are kept constant in real dollars.

Continued from previous page

contracts may not be available in the capacity constrained areas of Alberta until 2022 or 2023. New gas-fired facilities coming online prior to that time would need to obtain transportation service from an alternative source. Alternatives include obtaining unutilized firm transportation service from the secondary market or obtaining interruptible supply if available.

VI. Financial Assumptions

A. Discount Rate and Cost of Capital

An appropriate discount rate is needed for translating future cash flows into present values and deriving the annualized CONE value that makes the project net present value (NPV) zero. If the discount rate reflects the cost of capital associated with the business and financial risk of the investment, the sum of estimated annual project-related cash flows (reflected in the annualized CONE value) will allow for the full recovery of the investment and provide a compensatory return on the investment. Consistent with fundamental finance theory and valuation principles, it is standard practice to discount expected future all-equity cash flows (*i.e.*, the free cash flows available for distribution to *all* providers of financing, including both debt and equity holders) using an overall (after-tax) weighted-average cost of capital (sometimes referred to as WACC or after-tax WACC).[43] For this reason, our analysis of the discount rate needed for annualizing CONE is focused on determining the overall after-tax cost of capital, rather than the required return on equity, as would be the case in utility regulatory proceedings that determine allowed rates of return for the purpose of setting utility rates.

As pointed out earlier in this report, the cost of capital estimate is used only to determine the annualized value of CONE. It does not determine the financial return that investors will earn on their investment in the Alberta wholesale electricity markets. That earned return will be determined by the capacity market clearing price, which depends on the actual offers that suppliers make into the capacity market auction and the margins earned by the supplier in the energy and ancillary services markets. Suppliers will offer into the capacity market based on their actual costs, which can include financing costs that are higher or lower than our estimated cost of capital. If a supplier's bid is competitive, the market will clear at a price equal to or higher than that bid, and the supplier's investors will earn the return that is associated with that market price.

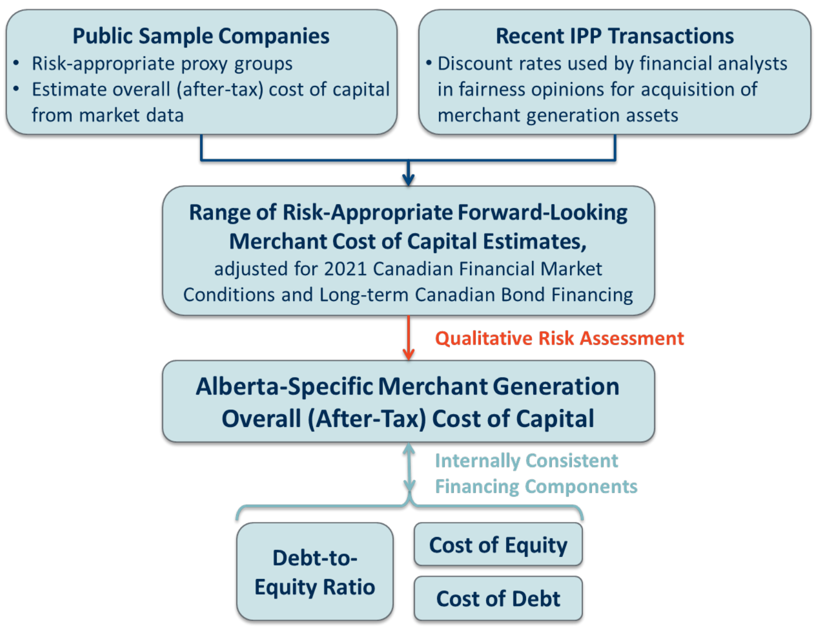
1. Approach and Methodology

To estimate the cost of capital for a greenfield, gas-fired, merchant power plant in Alberta, we start with an independent estimation of the cost of capital for publicly-traded Canadian generation companies with stock traded on the Toronto Stock Exchange and U.S. merchant generation companies (also called independent power producers or IPPs) with stock listed on the

[43] The discount rate is measured as the overall after-tax average cost of capital, which is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, weighted by the amount of debt and equity within a particular capital structure. The cash flows to which the discount rate is applied must be "all equity" cash flows (also called unlevered free cash flows), which include revenues less costs and taxes on income net of depreciation tax deductions (but not accounting for interest payments or their deductibility, since the tax benefit of debt is incorporated into the discount rate itself).

New York Stock Exchange (NYSE).[44] The cost of capital results for both sets of sample companies are then adjusted for Canadian financial market conditions, the consensus forecast of interest rate changes through 2021, and an assumption of long-term (20-year) bond financing. We compare the sample company results to the discount rates recommended by financial analysts in fairness opinions involving the acquisition of merchant generation assets and select our recommended discount rate from the very top of the range of the adjusted results and fairness opinions to reflect the unique higher risks of merchant generation investments operating in the proposed AESO capacity market. Figure 2 below depicts the framework in which we use market-based estimates of the cost of capital of merchant generation companies to develop an Alberta-specific value appropriate for discounting cash flows in the calculation of CONE.

Figure 2: Approach to Estimating Alberta Cost of Capital



Our approach relies on market data to estimate the overall (after-tax) cost of capital for each of the individual generation companies in the public-company samples. Recognizing that the sample companies' capital structures differ significantly from each other, and that market estimates of the cost of equity and cost of debt observed for the companies depend on the level of financial risk inherent in their capital structures, we develop market-based estimates of the cost of equity, cost of debt, and capital structure for each of the generation companies to calculate each company's overall (after tax) cost of capital. The company-specific overall cost of capital

[44] Subsequent to the study date for our analysis, two of the U.S. IPP companies, Calpine Corp. and Dynegy, Inc., have ceased trading on the NYSE upon completion of merger & acquisition transactions. Calpine was delisted from NYSE on March 8, 2018 when its acquisition by Energy Capital Partners (and other private investors) was finalized. Dynegy merged with Vistra Energy Corp. effective April 9, 2018 and the combined company's stock began trading under the ticker symbol for Vistra Energy as of that date.

results can then be compared and considered on the basis of how business risks—and not differences in financial leverage—affect the cost of capital. The range of overall (after-tax) cost of capital values reflect the risk of each generation company, which varies company-by-company based on (i) the mix of merchant, contracted, and regulated generation assets; (ii) the markets in which the merchant generation assets are located; and (iii) the proportion and type of non-generation assets in the company's business portfolio.

To ensure that our estimates of the overall cost of capital reflect the financial circumstances applicable to a merchant generation investment operating under the proposed Alberta capacity market, we employ the following methodological approach.

1. We estimate the overall cost of capital for both the Canadian and U.S. sample companies reflecting: (a) financial market inputs adjusted for Canadian market conditions (by using Canadian risk free rate, market risk premium, and tax rate inputs); (b) the consensus forecast of changes in Canadian interest rates through the relevant in-service year of 2021; and (c) the higher cost of debt associated with long-term bonds, including for below-investment grade sample companies (*i.e.*, 20-year yields for representative corporate debt issued by companies with a credit ratings in the BB or B range).[45]
2. We supplement these adjusted sample company results by considering published discount rates used by financial analysts in fairness opinions for recent market benchmark merger and acquisition transactions involving merchant generation companies, making the same adjustments as for the sample company estimates described above.[46]
3. We select the recommended discount rate from the range of cost of capital estimates from these adjusted sample-company and fairness-opinion results, relying in particular on the very top of the range of fairness opinions for merchant generation transactions (which is above the range of adjusted estimates for merchant generation companies or the more heavily contracted and therefore less risky Canadian generation companies) to reflect the higher risks of merchant generation investments in Alberta.

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[45] Given the relatively small size and riskier nature of the Alberta wholesale power market, we utilized the cost of debt for 20-year bonds to reflect sole reliance on higher-cost long-term financing over the full assumed economic life of the generation project, rather than the lower-cost, medium-term bond financing that we directly observe being utilized by the merchant generation companies in our samples.

[46] We supplement our analysis of publicly-traded companies with the discount rates used by financial analysts involved in estimating the value of major merchant generation transactions because the associated valuations are used by investors in support of their due diligence evaluation of the transactions. The analysts' recommended ranges of discount rates rely on methodologies that may account for market risks and estimation uncertainties very differently from ours. We also adjust these estimates for changes in projected interest rates between the date of the estimate and the 2021 project on-line date.

This approach uses the best available market data to assess investment risks in Alberta, considering the future market conditions that merchant generation developers are likely to face when financing generation projects in Alberta for a 2021 on-line date. It specifically takes into account how the overall investment risk for merchant generation under Alberta's proposed capacity market is expected to differ from the overall investment risk of the adjusted sample-company results.

During the stakeholder process, several stakeholders recommended that we consider developing the cost of capital for new generation facilities in Alberta by relying on surveys of project developers and financial institutions providing project financing. Based on our prior experience with interviewing developers and lenders in analyzing the financing cost of merchant generation companies, we believe relying on such a survey would introduce highly subjective and upwardly-biased results because: (1) developers and lenders tend to, consciously or not, provide cost of capital estimates consistent with the high returns they would like to earn rather than a competitive level of financing costs; (2) these survey results are not binding, and it is not clear that any actual bids or investments have been made with the expectation to earn these rates; and (3) it is unclear whether projects bid into the capacity market at some of the high recommended financing cost assumptions would be sufficiently competitive to clear in the auction. As was the case during Alberta's prior energy-only market, the most competitive of all proposed new generation development will clear in the market and succeed.

To avoid the potential upward bias of lender surveys, we prefer to rely on market data for publicly-traded sample companies (with appropriate adjustment for, and consideration of, differences in business risk for Alberta merchant generation investments), supplemented by benchmark cost of capital-based discount rates employed by investment analysts preparing fairness opinions for merchant generation companies as an additional reference point. The selected fairness opinions have been used by financial advisors to both the target and acquiring companies to value merchant generation merger and acquisition transactions for which there are corroborative market prices. Hence, the data from fairness opinions have the advantage of being an unbiased reference point. Compared to the potential bias introduced through lender surveys, we believe our approach yields an unbiased and market-based estimate of the cost of capital for merchant generation investments in Alberta.

2. Recommended Cost of Capital

Based on the high end of the range of reference points estimated in our analysis, we recommend a merchant generation overall (after-tax) cost of capital for Alberta of 8.5%. Assuming 50% of the investment is financed with debt at a cost of 6.0%, this recommendation corresponds to a simple overall cost of capital of 9.3% (when not reduced for the tax advantage of debt).

Since overall investment risk depends on the riskiness of the assets themselves, not on how they are financed, an individual investments' cost of equity and cost of debt components can be estimated for any particular financing arrangement (*i.e.*, different capital structures) consistent with this recommended overall cost of capital value. Table 11 shows that at a 50% debt and 50%

equity capital structure and a cost of debt of 6.0%, our recommended 8.5% overall after-tax cost of capital implies a cost of equity (and corresponding IRR on the equity portion of the investment) of 12.6%. In comparison, as noted above, at a more leveraged capital structure of 65% debt and a 6.5% cost of debt (reflective of increased default risk at the higher debt ratio), the implied cost of equity (and corresponding IRR on the equity portion of the investment) is 15.5% (reflecting the higher financial risk imposed on equity holders by taking on additional debt). Note that the cost of debt used in these calculations exceeds the actual (shorter-term) cost of debt reflected in the outstanding bonds on the sample companies' current balance sheets. This reflects the higher risks of merchant generation investments in Alberta's proposed capacity market, and incorporates the possibility that some of the new plants may be developed under a project financing framework rather than solely using balance-sheet-financing arrangements.[47]

Table 11: Components of Estimated Overall (After-Tax) Cost of Capital Consistent with 50% and 65% Debt Financing

Debt Fraction	**50%**	**65%**
Cost of Debt	6.0%	6.5%
Cost of Equity	12.6%	15.5%
Overall Cost of Capital	**9.3%**	**9.6%**
Income Tax Rate	27%	27%
Overall After-Tax Cost of Capital	**8.5%**	**8.5%**

Sources and notes:
Overall (After-Tax) Cost of Capital = (1 − Debt Fraction) × Cost of Equity + Debt Fraction * (1 − Income Tax Rate) × Cost of Debt. Values may not align due to rounding.

Figure 3 below shows our recommended overall (after-tax) cost of capital relative to the ranges of sample estimates and benchmark transaction discount rates. The horizontal red line represents the recommended value of 8.5% and the bars show the ranges of overall (after-tax) cost of capital results we considered in our analysis of comparable Canadian and U.S. publicly-traded companies for developing the merchant generation cost of capital. The light blue bars represent the range of overall cost of capital measured under current market conditions with debt costs estimated based on company-specific debt issuances and the range of discount rates reported in analysts' fairness opinions for merchant generation transactions.[48] The dark blue bars show the ranges of values

47 We have previously discussed the advantages and disadvantage of project financing and balance-sheet financing in the context of generation investments under the AESO's previous energy-only market design, available at http://files.brattle.com/files/6251_evaluation_of_market_fundamentals_and_challenges_to_long-term_system_adequacy_in_alberta_pfeifenberger_et_al_mar_2013.pdf.

48 The results spanned by the light blue bars reflect risk-free rates based on observed government bond yields at the time of our analysis and cost of debt estimates based on the observed market yields of each company's specific outstanding debt issuances. For the U.S. IPP companies, these estimates employ U.S. interest rates and tax rates. Note that shortly before we started this analysis, the U.S.

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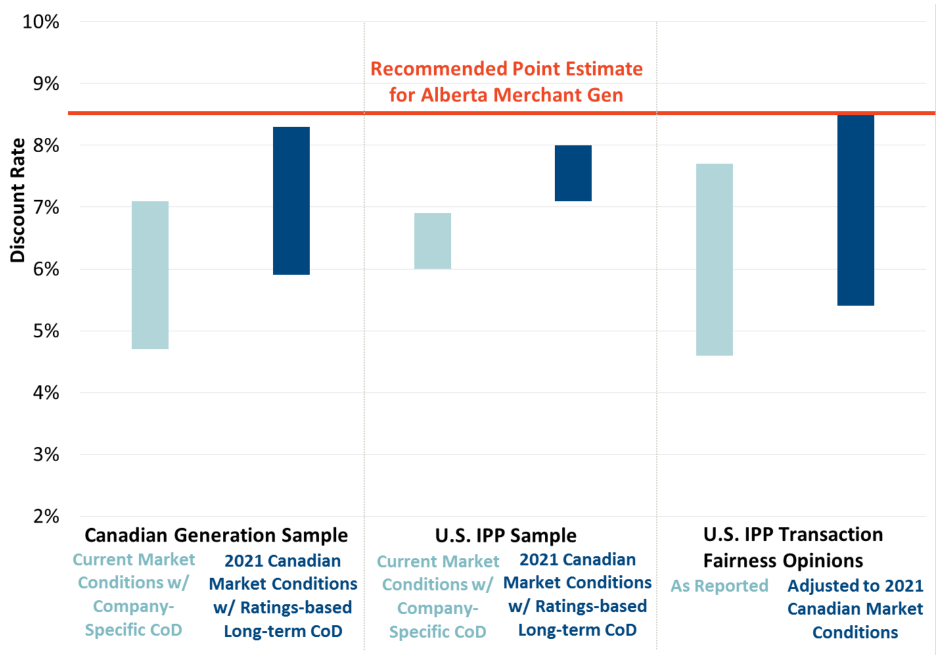
adjusted to reflect 2021 Canadian financial market conditions and the higher cost of long-term bond financing.[49]

Figure 3: Recommended Cost of Capital for Alberta Merchant Generation



As shown, the recommended cost of capital of 8.5% is higher than the top end of the (relatively wide) range of the adjusted results for Canadian generation companies under 2021 market conditions;[50] it is above the top end of the range of the U.S. merchant generation companies (adjusted for Canadian 2021 market conditions and long-term bond financing), and at the very top of the range of the discount rates used in fairness opinions for merchant generation

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Congress passed the Tax Cuts and Jobs Act of 2017, which made U.S. and Canadian (combined Federal and Provincial/State) corporate tax rates much more comparable.

49 The results spanned by the dark blue bars use inputs consistent with expected 2021 Canadian market conditions (*i.e.,* forecasted Canadian risk-free rates and Alberta-specific tax rates) for *both* the Canadian generating companies and the U.S. merchant IPP sample. Additionally, these results reflect cost of debt estimates based on long-term (20-year) bond yields implied by the companies' credit ratings. Note that these corporate bond yields are adjusted upward from current observed yields for corporate debt of the relevant ratings based on the expected (consensus forecast) increase in market interest rates.

50 Note that the upper end of the range for the Canadian generation sample under 2021 market conditions is set by AltaGas. The AltaGas cost of capital is higher than the rest of the Canadian generation sample by over 1.3%, with all other companies in the sample at or below 7.0%. AltaGas's higher cost of capital likely reflects the higher risk of the significant natural gas production and marketing operations within their business portfolio relative to the other Canadian generating sample companies.

transaction (adjusted for Canadian 2021 market conditions). We believe the high end of the U.S. IPP Transaction benchmark range (adjusted for forecast 2021 Canadian market conditions and long-term bond financing) is a highly-relevant reference point for future Alberta merchant generation investments, since these sample companies (and acquisition targets) have large portions of merchant generation assets and the top of the range reflects the unique higher risk of operating in the proposed Alberta capacity market.

3. Detailed Calculations

The remainder of this section explains the details of our analysis for developing the recommended discount rate for the CONE calculation. First, we show the results for the cost of capital analysis for U.S. and Canadian generation companies and IPPs and (as explained above) adjusted to reflect future market conditions in Alberta and the costs of long-term debt in the Canadian market. Second, we present evidence on the discount rates disclosed in fairness opinions for recent merger and acquisition transactions involving U.S. IPPs.[51] Third, we discuss how considerations of the specific dynamics of Alberta market affect the discount rate recommendations.

Cost of Capital for Publicly-Traded Generation Companies: As described above, we estimate the cost of capital for each publicly-traded generation company under two sets of conditions:

1. We calculate the cost of capital under current market conditions in each company's respective (Canadian or U.S.) market and based on the market cost of debt for the company's own outstanding bonds; then,
2. We adjust the values for the both the Canadian and U.S. generation companies based on the forecast 2021 risk-free rate for the Canadian market and the cost of long-term (20 year) debt based on the company's credit rating in the Canadian market (adjusted to reflect expected 2021 interest rate conditions).

Table 12 show the overall (after-tax) cost of capital results for the Canadian generation companies under the two sets of conditions. The values for the U.S. merchant generation companies are shown further below in Table 13.[52]

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51 We do not include private equity investors in our sample because their cost of equity cannot be observed in market data and private equity investment portfolios typically consist of investments in many different projects in many different industries. Nor do we include electric utilities focused on cost-of-service regulated businesses, as their businesses are mostly cost-of-service regulated with lower risks and a lower cost of capital than merchant generation.

52 The financial characteristics of the sample companies vary on an individual basis. For example, GenOn, a large subsidiary of NRG Energy, filed for bankruptcy in June 2017 and will be restructured as a standalone business. Calpine was acquired by a private investor consortium while Dynegy was acquired by Vistra Energy. We believe that these companies, each in differing positions, still can provide useful reference points for estimating the cost of capital for a merchant generator.

Table 12: Cost of Capital Estimates for Publicly-Traded Canadian Generation Companies

Sample Generation Companies				Current Market Conditions with Company-Specific Cost of Debt				2021 Canadian Market Conditions with Ratings-Based Long-Term Cost of Debt			
Company	S&P Credit Rating [1]	Adjusted Beta (5 Yr) [2]	Debt Ratio [3]	Current Risk-free Rate [4]	Current CAPM CoE [5]	Current Company-Specific CoD [6]	**Overall (after-tax) Cost of Capital** [7]	Forecast Risk-free Rate [8]	Forecast CAPM CoE [9]	Long-Term Rating-Based CoD [10]	**Overall (after-tax) Cost of Capital** [11]
Algonquin Power & Utilities Corp.	BBB	0.80	48%	2.41%	8.0%	4.3%	**5.7%**	3.60%	9.2%	5.8%	**6.9%**
AltaGas Ltd.	BBB	1.19	47%	2.41%	10.8%	4.2%	**7.1%**	3.60%	12.0%	5.8%	**8.3%**
ATCO Ltd.	A-	0.85	63%	2.41%	8.4%	3.5%	**4.7%**	3.60%	9.6%	5.0%	**5.9%**
Capital Power Corporation	BBB-	0.86	53%	2.41%	8.4%	4.0%	**5.5%**	3.60%	9.6%	5.8%	**6.8%**
Northland Power Inc.	BBB	0.87	58%	2.41%	8.5%	4.0%	**5.3%**	3.60%	9.7%	5.8%	**6.6%**
TransAlta Corporation	BBB-	1.29	68%	2.41%	11.5%	6.4%	**6.9%**	3.60%	12.6%	5.8%	**7.0%**
TransCanada Corporation	A-	0.96	50%	2.41%	9.1%	4.1%	**6.1%**	3.60%	10.3%	5.0%	**7.0%**

Sources and notes:
[1]: S&P Research Insight
[2]: Adjusted 5-year Weekly Bloomberg betas as of 3/6/2018
[3]: Debt Ratio (5 Year Average) calculated by Brattle using Bloomberg data
[4]: Canadian 20-Year Risk Free Rate, Bloomberg, average of most recent 15 trading days as of 3/8/2018
[5]: Risk Free Rate (2.41%) + [2] × Market Equity Risk Premium (7.00%)
[6]: Average of yield to maturities of company's outstanding bond issuances maturing after 2023; from Bloomberg as of 3/19/2018
[7]: [5] × (1 − [3]) + [6] × [3] × (1 − tax rate of 27%)
[8]: Consensus Forecasts Canadian 10 Year Risk Fee Rate Forecast for 2021 (3.2%) + historical average maturity premium for 20-year vs. 10-year Canadian Government bond yields (0.4% based on Bloomberg data)
[9]: Risk Free Rate (3.60%) + [2] × Market Equity Risk Premium (7.00%)
[10]: Forecast Canadian Risk-free Rate + average yield spread of A or BBB-rated Canadian corporate bonds over Canadian Government bond yields (Bloomberg. Monthly average, Mar. 2017 through Feb. 2018 for 20-year maturities)
[11]: [9] × (1 − [3]) + [10] × [3] × (1 − tax rate of 27%)

Table 13: Cost of Capital Estimates for Publicly-Traded U.S. Merchant Generation Companies

Sample Generation Companies				Current Market Conditions with Company-Specific Cost of Debt				2021 Canadian Market Conditions with Ratings-Based Long-Term Cost of Debt			
Company	S&P Credit Rating [1]	Adjusted Beta (5 Yr) [2]	Debt Ratio [3]	Current Risk-free Rate [4]	Current CAPM CoE [5]	Current Company-Specific CoD [6]	**Overall (after-tax) Cost of Capital** [7]	Forecast Risk-free Rate [8]	Forecast CAPM CoE [9]	Long-Term Rating-Based CoD [10]	**Overall (after-tax) Cost of Capital** [11]
NRG Energy	BB-	1.08	74%	3.04%	10.6%	6.0%	**6.1%**	3.60%	11.2%	7.8%	**7.1%**
Calpine Corp.	B+	0.97	65%	3.04%	9.8%	6.0%	**6.3%**	3.60%	10.4%	8.7%	**7.8%**
Dynegy Inc.	B+	1.17	70%	3.04%	11.2%	6.9%	**6.9%**	3.60%	11.8%	8.7%	**8.0%**
Atlantic Power Corp.	B+	1.28	80%	3.04%	12.0%	6.9%	**6.4%**	3.60%	12.5%	8.7%	**7.6%**

Sources and notes:
[1]: S&P Research Insight
[2]: Adjusted 5-year Weekly Bloomberg betas as of 3/6/2018
[3]: Debt Ratio (5 Year Average) calculated by Brattle using Bloomberg data
[4]: US 20-Year Risk Free Rate, Bloomberg, average of most recent 15 trading days as of 3/8/2018
[5]: Risk Free Rate (3.04%) + [2] × Market Equity Risk Premium (7.00%)
[6]: Average of yield to maturities of company's outstanding bond issuances maturing after 2023; from Bloomberg as of 3/19/2018
[7]: [5] × (1 − [3]) + [6] × [3] × (1 − U.S. tax rate of 26.1%)
[8]: Consensus Forecasts Canadian 10 Year Risk Fee Rate Forecast for 2021 (3.2%) + historical average maturity premium for 20-year vs. 10-year Canadian Government bond yields (0.4% based on Bloomberg data)
[9]: Risk Free Rate (3.60%) + [2] × Market Equity Risk Premium (7.00%)
[10]: Forecast Canadian Risk-free Rate + average yield spread of Canadian BBB rated corporate vs. Canadian Government bonds + average non-investment grade premium for BB or B rated corporate bonds vs. BBB rated corporate bonds (derived based on Bloomberg U.S. corporate bond indexes for 20-year maturities).
[11]: [9] × (1 − [3]) + [10] × [3] * (1 − Alberta tax rate of 27.0%)

We derived the cost of capital estimates for the selected companies presented above using the following implementations of standard finance techniques.

Cost of Equity (CoE): We estimate the cost of equity (or Return on Equity, ROE) using the Capital Asset Pricing Model (CAPM) applied to samples of U.S. and Canadian generation companies.[53] The cost of equity for each company is derived as the applicable risk-free rate *plus* a risk premium given by the expected risk premium of the overall market *times* the company's "beta."[54]

- For the "current conditions" estimates, we use an observed risk-free rate of 2.41% in Canadian markets and 3.04% in U.S. markets based on the market yields for 20-year Treasury bonds in each market as of the date of the analysis.
- We estimate the expected market risk premium to be 7.0% based on the historical long-term average for the Canadian market, the long-term average for the U.S. market, and the forecasted market risk premiums (MRPs) for both markets.[55]
- The "beta" describes each company stock's historical (five-year) correlation with the overall market, where the "market" is taken to be the Standard & Poors (S&P) TSX index for Canadian generation companies and the S&P 500 index for U.S. companies. We use 5-year adjusted betas reported by Bloomberg.
- For CoE estimates representative of 2021 Canadian market conditions, we replace the current U.S. and Canadian risk-free rates with a forecasted value based on the 2021 yield on 10-year Canadian Government bonds (3.2%), adjusted upward to

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53 Our recommendations are based on results derived using the traditional CAPM formulation, as well as the "Empirical CAPM" (ECAPM), which adjusts for the empirically observed tendency of the relationship between equity returns and market beta to be flatter than that predicted by the CAPM. We further confirmed that other cost-of-capital methodologies—such as discounted cash flow (DCF) models (for sample companies having the necessary data) and implementations of the CAPM using the Hamada procedure to unlever and relever betas—produced cost of capital ranges that were consistent with the CAPM and ECAPM results.

54 See, for example, Richard Brealey, Stewart C. Myers, and Franklin Allen (2014), Principles of Corporate Finance, New York: McGraw-Hill/Irwin (Chapter 8).

55 Duff and Phelps International Guide to Cost of Capital, 2017 (arithmetic average of excess market returns over 20-year risk-free rate from 1926 to March 2017 for the U.S. is 6.9% and 5.7% for Canada). Bloomberg's forward-looking estimate of market-specific MRPs (which Bloomberg refers to as the "Country Risk Premium" or CRP) was 9.4% for Canada and 7.3% for the U.S. at the end of February 2018. While the average of the historical and forecasted Canadian MRP is slightly above 7%, the high degree of integration between the Canadian and U.S. markets indicate that it is appropriate to consider MRP evidence from both markets as representative for Canadian market conditions, as more than half of the foreign direct investments into Canada and over 60% of Canada's direct investments abroad are from/into the U.S.
(See CANSIM at https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=361004740.)

3.6% by a representative historical average maturity premium for 20-year versus 10-year Canadian Government bonds.[56]

The resulting CoE ranges under 2021 Canadian market conditions are from 9.2% to 12.6% for the Canadian sample companies and from 10.4% to 12.5% for the U.S. IPPs.

In addition to this baseline analysis, we also looked to the results from the Empirical CAPM, and to discounted cash flow (DCF) results for companies with data available for the DCF estimation. These results were generally in line with the CAPM results cited above although the DCF results spanned a wider range.[57]

Cost of Debt (CoD): Similar to the cost of equity, we estimate the cost of debt under two conditions: (i) the CoD under current market conditions in each market is based on the average bond yields on the actual outstanding issuances for each merchant generation company (issuer ratings) of company bonds with 5 or more years of remaining duration; (ii) the CoD under forecasted 2021 Canadian market conditions is based on average long-term (20-year) Canadian corporate bond yields associated with the credit rating of each sample company. The rating-based average yields, based on a sample of similarly-rated corporate bonds, are generally preferable to the company's actual CoD, which could be more influenced by company- and issue-specific factors.[58] Company-specific CoDs could carry real-time industry-wide credit information that the typically static credit ratings for a broad swath of industries are slower to incorporate.

We additionally rely on the expected ratings-based yield of long-term (20-year) bonds, rather than the actual durations and yields of the companies' debt, to reflect the higher cost of long-term debt financing of merchant generation in Alberta. The resulting investment-grade CoD ranges under 2021 Canadian market conditions as applied to the investment-grade Canadian sample companies range from 5.0% to 5.8%. For the below-investment-grade U.S. IPPs, the yields range from 7.8% to 8.7%. The use of these higher long-term, ratings-based yields reflects the higher risks of merchant generation investments in Alberta's proposed capacity market (compared to the risks associated with the sample companies and actually reflected on their current balance sheets), and incorporates the possibility that some of the new plants may be

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56 The historical average maturity premium for 20-year versus 10-year Canadian Government bonds is 0.4% based on Bloomberg data.

57 ECAPM results for the Canadian power producers ranged from 8.3% to 12.2% and from 9.9% to 12.1% for the U.S. IPPs. DCF results for the Canadian power producers ranged from 7.8% to 19.0%—data for this analysis were not available for the U.S. IPPs who do not generally pay dividends.

58 These idiosyncratic factors include the issuers' competitive positions within the industry, and the debt issues' seniority, callability, availability of collateral, *etc*. For example, the sample Canadian companies' credit ratings range from "A-" to "BBB-," with associated yields on company-specific issuances of 3.5% to 6.4%, while the U.S. companies have sub-investment grade ("B+" and "BB-") debt ratings with an associated company-specific CODs, which range from 6.0% to 6.9%.

developed under a project financing framework rather than solely using balance-sheet-financing arrangements.

Debt/Equity Ratio: To estimate the overall cost of capital for each of the sample companies, we utilize the five-year average debt/equity ratio for each generation company based on market capitalization data and company financial reporting of book value of debt (with adjustments for the difference between estimated fair market value and carrying value), all sourced from Bloomberg.

The debt ratios of U.S. merchant generation companies operating in the much larger and well-established U.S. energy and capacity markets range from 65% to 80%. We view a 65% debt ratio—which is the *lowest* degree of leverage observed in the market-value capital structures of the U.S. IPP companies—as an upper end of possible capital structures for merchant plants operating in the AESO's proposed capacity market. However, recognizing that (at least initially) the higher risks of operating in the AESO's proposed market may constrain the ability to finance merchant generation with higher levels of debt, our baseline recommendation employs a lower 50% debt ratio.[59] This 50% debt fraction scenario is at the very low end of both (1) the 47% to 68% debt ratio range of our sample of Canadian generation companies; and (2) the 50%-65% range of debt ratios that, based on our experience, is typically employed for project-level and balance-sheet financing of merchant generation plants operating in existing capacity markets.[60]

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59 As described in Section VI.B below, our calculation of interest during construction (IDC) is based on an assumption of 50% debt financing. Otherwise, the financial assumptions underlying our CONE calculations depend only on our recommended 8.5% overall (after-tax) cost of capital, as derived from the observed market data for the sample companies and fairness opinions of merchant generation transactions. Recognizing that the overall cost of capital is based on the risk of the asset and does not vary substantially across a reasonable range of capital structures, our cost of capital recommendation for the purpose of calculating CONE does not depend on any specific assumption about the proportion of debt and equity used to finance new merchant generation in the Alberta market. Rather, by focusing on the overall required rate of return, our approach allows for a range of reasonable financing structures, which will likely be in the 50-65% debt range based on the available market data, industry experience, and credit rating agency guidelines.

60 At an assumed 50% debt fraction, the projected debt-to-EBITDA ratio inherent in the CONE calculations is 4.0x in the first year and declines as the debt balance is paid off. These 4.0-or-less levels of the debt-to-EBITDA credit metric are well within the range that S&P recently noted that U.S. IPPs should start to target by reducing their leverage levels to address increasing risk presented by the new technologies, such as storage:

> "We believe that IPPs will need to recalibrate their capital structure no higher than 4x-4.5x adjusted debt to EBITDA over the next three to five years—a level consistent with current expectations of the forward commodity curves. To be clear, we think this threshold is not a ratings target but one that would allow an IPP to withstand potential future attenuation of EBITDA from disruptive technologies."

Continued on next page

The 50% baseline scenario is also lower than the 60% debt ratio that the U.S. Federal Energy Regulatory Commission (FERC) has previously found to be a reasonable debt ratio for the assumed financing associated with the CONE determination for merchant generation investments in PJM's capacity market.[61]

Cost of Capital Benchmarks from Fairness Opinions Issued for Recent Merchant Generation Transactions: The additional cost of capital reference points shown on the right side of Figure 3 above represent publicly-available discount rates employed by financial advisors and analysts in valuations associated with mergers and acquisitions of merchant generation assets operating in competitive wholesale power markets. While there are no details provided on how these overall (after-tax) cost of capital ranges were developed by the financial analysts, these values provide useful reference points for estimating the cost of capital for merchant generation companies. Importantly, as discussed above, these discount rates are associated with published valuations in "fairness opinions" that support the reasonableness of the market-determined transaction values.

For the current analysis, we found three such reference points to inform the recommended overall cost of capital for discounting the unlevered cash flows of merchant generation investments, as shown in Table 14: (1) the acquisition of Talen Energy by Riverstone Holdings (Citigroup recommending that the transaction-related cash flows be discounted with an overall after-tax cost of capital of 5.9% to 7.3%);[62] (2) the acquisition of Calpine by Energy Capital Partners (Lazard Frères recommending 5.75% to 6.25%);[63] and (3) the acquisition of Dynegy by Vistra (Citigroup, Morgan Stanley, and PJT recommending 4.7% to 7.7%).[64] Importantly, the portfolios of generating assets acquired in these transactions were predominantly devoted to merchant generation activity (as opposed to earning revenue from regulated rates or through long-term PPA contracts).

The wide range of discount rates for the Vistra-Dynegy transaction is due to the use of fairness opinions from three different financial advisors (Citigroup for Vistra, Morgan Stanley and PJT for

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S&P Global Ratings, Independent Power Producers Update: The Greatest Risk Is Not Taking One, December 6, 2017, p. 11. Available at https://www.spratings.com/documents/20184/1634005/SPGR_ProjFin_Independent+Power+Producers_Final/73a89a1a-e492-4207-b6fa-ba1982195573

61 149 FERC ¶ 61,183 (November 28, 2013), available at https://www.ferc.gov/CalendarFiles/20141128172749-ER14-2940-000.pdf.

62 Preliminary Proxy Statement, Schedule 14A, filed by Talen Energy Corporation with the U.S. Securities and Exchange Commission (SEC) on July 1, 2016.

63 Definitive Proxy Statement, Schedule 14A, filed by Calpine Corporation with the SEC on November 14, 2017. Lazard estimated that the cost of equity (used to discount the levered cash flows associated with Calpine's generation business) ranges from 11.75% to 12.75%.

64 Definitive Proxy Statement, Schedule 14A, filed by Dynegy Inc. with the SEC on January 29, 2018. The investment advisors estimated Dynegy's cost of equity to range from 6.9% to 13.75%.

Dynegy), each using a distinct range of discount rates for evaluating the Dynegy acquisition: 4.7% to 5.5% as used by Morgan Stanley, 5.95% to 6.95% as used by PJT, and 7.0% to 7.7% as used by Citigroup. This rather wide range of discount rates (4.7% to 7.7%) and wide discrepancy of discount rates used by three different investment banks evaluating the very same transaction reflects the uncertainty in cost of capital estimates for the merchant generation industry.

In a manner similar to our estimation methodology for the Canadian and U.S. sample companies, we adjusted these transaction fairness opinion benchmark discount rate values to account for differences in the risk-free rates between the U.S. and Canadian markets and for changes in the market conditions between the time they were reported and 2021. Table 14 below shows the values as originally reported and with the adjustment to be applicable to a future merchant investment in Alberta.

Table 14: Discount Rates from Fairness Opinions of Merchant Generation Companies

Transaction	Financial Analysts	Report Date	Reported in Fairness Opinion	Adjusted to 2021 Canadian Market Conditions
Riverstone-Talen	Citigroup	Dec-15	5.9% - 7.3%	7.5% - 8.5%
ECP-Calpine	Lazard Fréres	Jun-17	5.75% - 6.25%	7.3% - 7.8%
Vistra-Dynegy	Several	Jan-18	4.7% - 7.7%	5.4% - 8.5%
	Morgan Stanley		*4.7% - 5.5%*	
	PJT		*5.95% - 6.95%*	
	Citigroup		*7.0% - 7.7%*	

Sources and notes:
SEC Schedule 14A Proxy Statements; 2021 Canadian Market Conditions values derived by adjusting Reported values for difference between forecasted 2021 Canadian risk-free rates and corporate bond yields and corresponding U.S. interest rates that prevailed at the time the Fairness Opinions were published; adjustments assume ⅔ debt fraction.

Recommended Discount Rate for Merchant Generation in Alberta's Proposed Capacity Market: The appropriate overall (after-tax) cost of capital for the CONE study should reflect the systematic financial market risks of the expected future cash flows for a new merchant generating project operating under the AESO proposed wholesale power market design. For a pure merchant project in AESO's capacity market, the risks would be substantially greater than for the average portfolio of generation companies that have their assets under long-term contracts.[65] As we discuss further, the risk of operating in the proposed Alberta capacity market will exceed the risks of operating in the established capacity markets of other regions. We considered the following aspects of the risk that new merchant generation faces in the Alberta wholesale market:

65 This is not to say that the reference Alberta merchant project would not arrange some medium-term financial hedging tools.

- *Market Size*: The Alberta market (2017 peak load: 11,473 MW) is significantly smaller than other regions with capacity markets, such as ISO-NE (23,968 MW), NYISO (29,699 MW) and PJM (145,331 MW).[66] The smaller size will necessarily mean less liquidity and more volatility associated with the entry and retirement of individual resources.
- *Limited Liquidity and Forward Hedging Opportunities.* The smaller market size also means there are fewer participants, fewer trading partners, and fewer financial intermediaries operating in the market. This reduces market liquidity and opportunities for hedging merchant generation exposure to volatile market prices.
- *One-Year Contract Period*: Unlike some other capacity markets, such as ISO-NE or the U.K., the AESO is proposing that new resources will not be able to lock-in the first year clearing price over a multi-year period. In contrast, ISO-NE allows for new resources to lock-in the first year price over seven years and the U.K. is offering a 15-year lock-in (though note that neither New York ISO nor PJM offers a multi-year lock-in).
- *New Market Design*: The Alberta market is undergoing a significant period of reform that combines a new capacity market with changes to the energy market design. The full risk implications of these changes are unknown to resources developers, especially those without experience of operating in a capacity market or being able to diversify the investment portfolio across different resources and markets. At the same time, the risk under the proposed three-year forward capacity market will be less than the risks of merchant generation companies operating in energy-only markets (such as the AESO's current market design) or operating solely in short-term power markets (like uncontracted generation assets in CAISO).[67]

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66 AESO, AESO 2017 Annual Market Statistics, March 2018; ISO-NE, ISO New England Public Monthly Peak Load and Energy Data 2017, downloaded in August 2018; NYISO, 2018 Power Trends: New York's Dynamic Power Grid, May 2018; PJM, PJM Load Forecast Report January 2018, December 2017.

67 See: S&P Global Ratings, Industry Top Trends 2018: North America Merchant Power, January 25, 2018, p. 11. Available at https://www.spratings.com/documents/20184/1818036/Industry+Top+Trends+2018+North+America+Merchant+Power/8e2be62d-4d1a-4c8c-b3cf-7b85b51354dd

> "Alberta plans to transition to an energy and capacity payment market from an energy-only market by 2021. We believe that this would increase the competition for the incumbent players. On the other hand, we expect that power price volatility will decrease and that would lessen the re-contracting risk for the IPPs once their Alberta PPAs terminate in 2020."

- *Market Power Mitigation*: More restrictive market power mitigation may reduce generators' ability for cost recovery (compared to the currently-applicable mitigation regime). At the same time, the proposed mitigation mechanisms in Alberta will be less restrictive than in other regions with capacity markets. Less restrictive mitigation in combination with large incumbent generators may increase the risk for new entrants that are unable to exercise market power but are exposed to potential exercise of market power by the large resource owners.
- *Political, Regulatory, and Governance Risks*. The Alberta capacity market may be perceived as less stable due to its single-Province nature that exposes investors to higher risks associated with political interventions and its implications for providing a stable regulatory environment. The effectiveness of proposed capacity market governance structures to mitigate these risks is still somewhat uncertain.
- *Risk Mitigation of 3-Year Forward Capacity Payments.* While the proposed Alberta capacity markets may be more risky than the larger and well-established capacity markets in other jurisdictions, the annual capacity payments and three-year forward nature of these payments will reduce investment risks relative to Alberta's current energy-only market design. It will mean that the risk is mitigated relative to other capital-intensive industries that do not enjoy such three-year forward capacity payments for 100% of their qualified output.

Based on the set of reference points shown in Figure 3 above and the recognition that merchant generation risk in the proposed AESO capacity market exceeds those of other markets and the average risk of the publicly-traded sample generation companies (as explained above), we believe that selecting from the very top of the available reference points—yielding a 8.5% overall (after-tax) cost of capital—is the most reasonable discount rate for the purpose of estimating CONE.[68]

Our recommendation is at the very top of the ranges of cost of capital estimates using forecasted 2021 interest rates and forecasted ratings-implied estimates of long-term (20-year) debt financing costs. In recognition of the (at least initially) higher risk of operating merchant generation in Alberta's proposed capacity market, this recommendation is well above our recommendation in other capacity markets or the current cost of capital estimates for the Canadian and U.S. companies as well as the unadjusted fairness opinions.

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[68] As discussed earlier, this recommendation corresponds to an overall cost of capital (also referred to as weighted-average cost of capital or WACC), without considering the tax advantage of debt payments, that is 9.3%—consistent with a 12.6% IRR on the equity portion of the investment at 50% debt financing and a 6.0% cost of debt.

B. Other Financial Assumptions

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, and interest during construction.

Inflation rates affect our CONE estimates by forming the basis for projected increases in plant capital costs from 2018 to 2021 dollars and various fixed O&M cost components over time. Canada's long-term inflation target is 2.0%.[69] The most forward-looking forecast in the Consensus Economics report for Canada is 2.0%.[70] Based on these sources, we assumed for the CONE calculations an average long-term inflation rate of 2.0%.

Corporate income tax rates affect both the cost of capital and cash flows in the financial model used to calculate CONE. We calculate income tax rates based on current federal and provincial tax rates and statutes. We use a net federal corporate income tax rate of 15%, which is derived from the base rate of 38% less the 10% federal tax abatement on income earned in a Canadian province and the 13% general tax deduction.[71] We use an income tax rate of 12% for Alberta, yielding a combined federal and provincial corporate income tax rate of 27%.[72]

We calculate tax depreciation using the capital cost allowance (CCA) process defined by the Canada Revenue Agency. In Canada, depreciable property is grouped into a number of different classes. Each class has a different rate at which the relevant property can be depreciated each year. Most of the components of the reference technology build fall into five of these classes. The details of these class assignments are in Table 15. Reflecting stakeholder input, we calculated a weighted-average rate across these five classes, which is approximately 14% per year for the CC, 12% for the Aero CT, and 11% for the Frame CT. We assumed that all other depreciable costs, including labor, are spread evenly among the cost categories. Land is excluded because it is not a depreciable cost.

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69 As stated on the Bank of Canada's website, the "Bank of Canada aims to keep inflation at the 2 per cent midpoint of an inflation-control target range of 1 to 3 per cent. The inflation target is expressed as the year-over-year increase in the total consumer price index (CPI)." Bank of Canada (2018), Inflation, available at https://www.bankofcanada.ca/core-functions/monetary-policy/inflation/.

70 Consensus Economics Inc. (2018). Consensus Forecasts*,* E-mail Edition, London: Consensus Economics Inc., April 9, 2018.

71 Government of Canada (2018). Corporation Tax Rates, available at https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/corporations/corporation-tax-rates.html.

72 Government of Alberta (2018). Business Taxes, available at https://www.alberta.ca/budget-revenue.aspx.

Table 15: Capital Cost Allowance Classes

Cost Category	CCA Class	Rate	Share of Costs		
			Aero CT	Frame CT	CC
Combustion Turbines	48	15%	63%	47%	31%
HRSG/Steam Turbine	43.1	30%	--	--	18%
Electrical Interconnection	47	8%	10%	22%	13%
Materials and Equipment	17	8%	22%	28%	36%
Gas Interconnection	1	4%	5%	4%	1%
Weighted Average Rate			**12%**	**11%**	**14%**

Sources and notes:
Government of Canada, Justice Laws Website, Income Tax Regulations (C.R.C., c. 945), Part XI and Schedule II, available at http://laws-lois.justice.gc.ca/eng/regulations/C.R.C.,_c._945/. Percentages may not add due to rounding.

To calculate the annual value of depreciation, the "depreciable costs" (different from the overnight and installed costs referred to earlier in the report) for a new resource are the sum of the depreciable overnight capital costs and the accumulated interest during construction (IDC). Several capital cost line items are non-depreciable, including working capital and non-fuel inventories, and have not been included in the depreciable costs. IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 50% debt and 6.0% CoD.

VII. Annualized CONE Estimates

Translating investment costs and going-forward fixed costs into the annualized costs to be recovered in the wholesale electricity markets requires an assumption about how net revenues are received over time. "Level-nominal" cost recovery assumes that net revenues will be constant in nominal terms (*i.e.*, decreasing in real, inflation-adjusted dollar terms) over the 20-year economic life of the plant. A "level-real" cost recovery path starts lower in the first year (by about 13.5%) then increases at the rate of inflation (*i.e.*, is constant in real dollar terms).[73]

While there is no perfect way to capture developers' expectations for their future cost recovery paths, our previous CONE studies reviewed long-term trends in plant costs and efficiencies to understand the likely long-term drivers of new-entry offers and whether a developer would expect that market revenues would lead to a more front-loaded or more back-loaded recovery of investment costs.[74] We found that while turbine costs have increased in *absolute* terms over the previous 20 years, turbine costs have declined on a *per-kW basis* since 2010, and these per-kW costs have been approximately constant in nominal terms over the last 20 years (*i.e.*, when adjusted for higher capacity of gas turbines, current costs per kW are approximately the same as those in 1998).[75] Developers of new generation resources must therefore consider that the gas generation technologies are likely to continue to see periodic incremental improvements over time, similar to those experienced over the last 20 years. Investors in new generating resources have to consider the possibility that their future net revenues may erode (relative to increasing with inflation) as technological innovation and environmental policies favor different types of technologies, such as renewable generation combined with storage.

Due to the low escalation rate in the cost of gas turbine plants in $/kW terms and the potential for similar cost-reductions to arrive periodically over the 20-year economic life of new natural gas-fired generating plants, we recommend adopting the *level-nominal* approach for setting the 2021/2022 CONE value, such that net revenues for the marginal resources in the AESO capacity market will remain constant in nominal terms over time (but declining in real terms to reflect the observed trend of technological improvements that reduce real costs).

Figure 4 below depicts the project cash flows for the reference CC from commencement of the assumed 36-month construction schedule in November 2018 through the assumed 20-year

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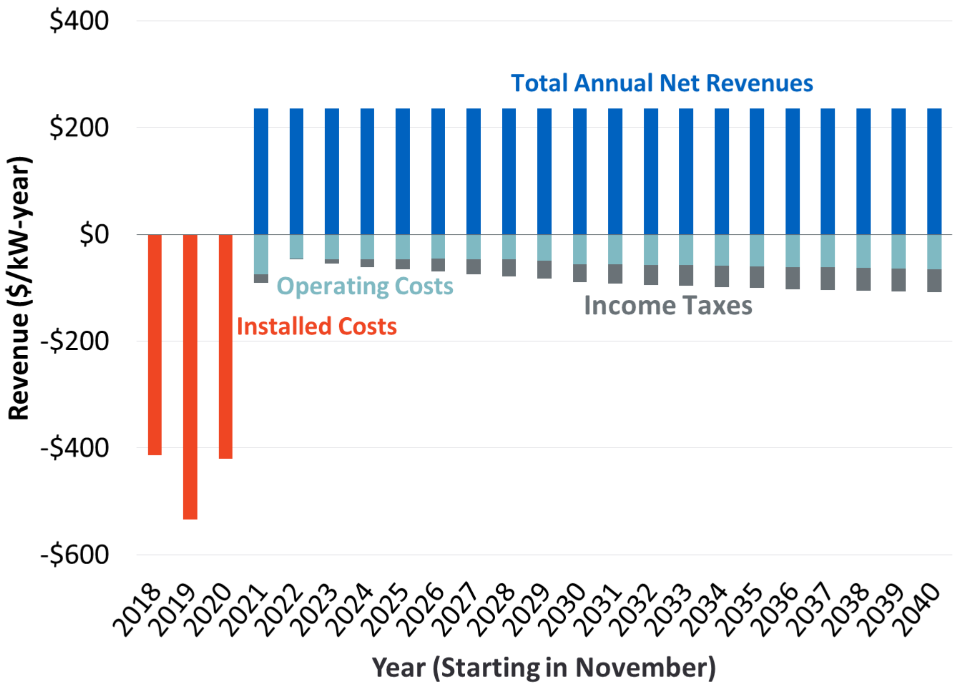
73 Both cost recovery paths (level-real and level-nominal) are calculated such that the NPV of the project is zero over the 20-year economic life.

74 See The Brattle Group (2018), PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, pp. 48–50.

75 Both S&L's estimates of the trend in F-class turbine costs per kW and the U.S. Producer Price Index (PPI) turbine cost index adjusted for turbine capacity show that 2017 turbine costs are only slightly more expensive on a nominal $/kW basis than 20 years ago.

economic life of the asset starting in November 2021, reflecting the assumed level-nominal cost recovery.

Figure 4: Reference CC Project Cash Flows and Depiction of CONE



The red bars in 2018 to 2020 represent the initial capital investment costs and the teal bars for 2021 to 2040 reflect the annual fixed operating costs, both representing cash expenditures (shown as negative values). The (negative) gray bars depict income taxes, which are lower in the earlier years of operation due to the tax benefits of the front-loaded depreciation tax shield.[76] Finally, the (positive) blue bars represent cash flows associated with annual net revenues needed to recover the depicted costs, including a compensatory return on investments. The value of these net revenues corresponds to the annualized CONE values determined in this study. We determine these annual net revenues such that the discounted value of project cash flows over the assumed 20-year economic life are equal to zero when using the previously-determined 8.5% discount rate. Because we have assumed a "level-nominal" cost recovery path, the annual net revenues remain constant in nominal dollars over the economic life (as opposed to a "level real"

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76 Income taxes in the first year of operation are higher than the years following due to the half-year rule, which permits only half the applicable CCA to be claimed in the year of a property's acquisition. See Government of Canada, Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, available at https://www.canada.ca/en/revenue-agency/services/tax/technical-information/income-tax/income-tax-folios-index/series-3-property-investments-savings-plans/series-3-property-investments-savings-plans-folio-4-capital-cost-allowance/income-tax-folio-s3-f4-c1-general-discussion-capital-cost-allowance.html#p1_38.

cost recovery path, under which CONE would be based on the 2021 value of net revenues, which would be assumed to increase with inflation over time).

Table 16 below shows a summary of our plant capital costs, annual fixed costs, and levelized CONE estimates, presented in terms of installed capacity (ICAP), for the reference technologies for the 2021/2022 delivery year. CONE is lowest for the Frame CT at $114.1/kW-year. The Aero CT has the most capacity recently built or permitted in Alberta. It has the lowest total capital costs, though it has the highest CONE estimate at $244.2/kW-year due to its much smaller capacity. The largest reference resource is the CC, with substantially higher capital costs than both CTs, but economies of scale that yield a CONE value of $236.1/kW-year, just beneath the Aero CT.

Table 16: Recommended CONE for the Reference Technologies for the 2021/2022 Delivery Year (2021 CAD)

Reference Technology	Winter Capacity	Overnight Capital Costs	Overnight Capital Costs	Overall (After-Tax) Cost of Capital	Annual Carrying Charge	Plant Capital Costs	Fixed O&M Costs	Gross CONE
	MW	*$million*	*$/kW*	*%*	*%*	*$/kW-yr ICAP*	*$/kW-yr ICAP*	*$/kW-yr ICAP*
Aeroderivative CT	93	$138	$1,479	8.5%	12.6%	$186.9	$57.3	$244.2
Frame CT	243	$163	$671	8.5%	12.7%	$85.0	$29.2	$114.1
Combined Cycle	479	$657	$1,371	8.5%	13.3%	$182.2	$53.9	$236.1

Sources and notes:
CONE values are expressed in 2021 dollars and Installed Capacity (ICAP) terms. Overnight capital costs are in nominal dollars. The annual carrying charge accounts for the cost recovery path, financing, depreciation, and taxes and is derived by dividing plant capital costs ($/kW-yr) by overnight capital costs ($/kW)..

Figure 5 below presents a sensitivity of the Aero CT CONE estimates to different inputs and assumptions. Capital costs can vary widely and have a very large impact on CONE. For example, if total capital costs were 20% lower, the Aero CT CONE value would be $206.8/year, 15.3% lower than our estimated CONE of $244.2/kW-year. As a much lower proportion of total costs, the same magnitude of variance in the fixed O&M costs only affects the Aero CT CONE by plus or minus 4.7%. The overall after-tax cost of capital used as the discount rate for project cash flows has a relatively minor impact on CONE: an increase of 1% to the assumed cost of capital (9.5% instead of 8.5%) only increases the Aero CT CONE value by $16.1/kW-year (6.6%). Increasing the economic life by five years has a relatively minor impact, decreasing CONE by $13.6/kW-year (-5.6%) for the Aero CT. However, an equivalent decrease in the economic life increases CONE by almost twice that amount. As discussed above, we recommend the use of level-nominal CONE values. Level-real CONE for the Aero CT would be $211.8/kW-year (-13.3%), lower than the first-year level-nominal CONE, but rising over time with inflation. A similar analysis for the Frame CT and CC is given in Figure 6 and Figure 7, and the relative patterns are the same.

Figure 5: Sensitivity Analysis of CONE Estimates—Aeroderivative CT

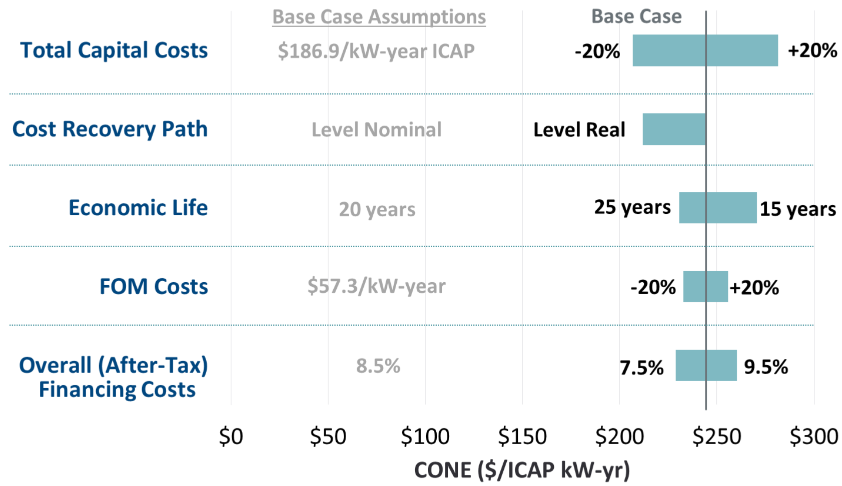


Figure 6: Sensitivity Analysis of CONE Estimates—Frame CT

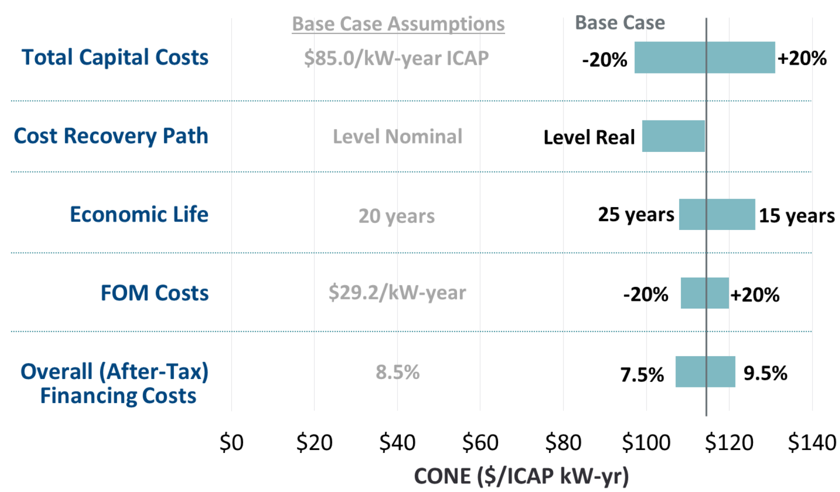
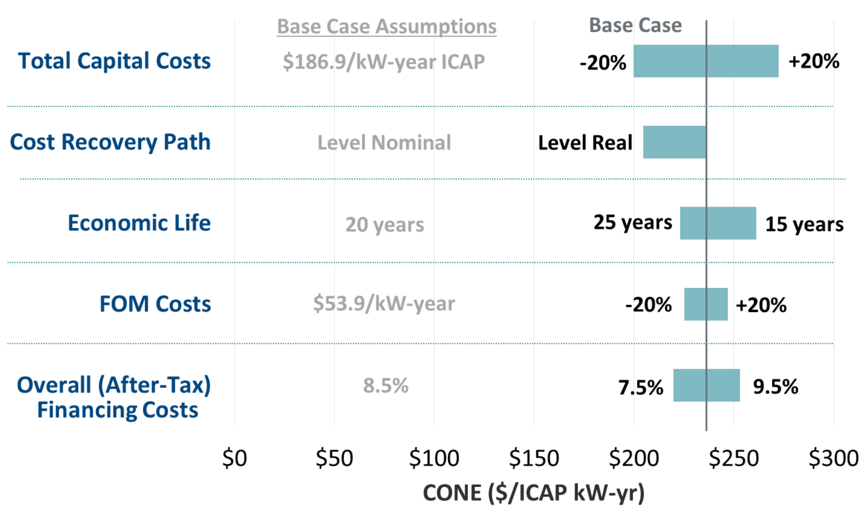


Figure 7: Sensitivity Analysis of CONE Estimates—Combined Cycle



VIII. CONE Updates

AESO's capacity market design specifies that detailed CONE studies, such as this one, will be performed every four to five years and that CONE will be escalated in between, prior to each base auction, using cost indices. We recommend that AESO update the CONE value during these periods based on the changes in a composite cost index that accounts for the major costs components of a new facility, specifically labor, turbines, and materials, and their relative weight in the total overall plant capital costs.

To reflect labor costs, we recommend using construction union wage rates for Edmonton specific to the electrician trade reported by Statistics Canada.[77] Using the Edmonton rate accounts for the greater wage volatility in Alberta compared with the country as a whole, and in S&L's experience, electricians constitute a representative labor category for the trades associated with power plant construction. We recommend using the Canadian gross domestic product (GDP) deflator, also reported by Statistics Canada, to reflect materials costs.[78] Given that the turbines will be sourced from the U.S., the updating index should reflect changes in U.S. turbine costs as well as changes in the exchange rate. To account for turbine costs, we recommend the Producer Price Index (PPI) reported by the U.S. Department of Labor Bureau of Labor Statistics (BLS) for turbines and generator sets adjusted for the U.S./Canadian exchange rate.[79]

We recommend that the AESO update the CONE value prior to each base auction using this composite index approach. Table 17 below shows that we recommend that the AESO weight the components of the composite index for the Aero CT based on 25% labor, 40% turbine, and 35% materials and other equipment. For the Frame CT, we recommend weighting the component indices based on 25% labor, 30% turbine, and 45% materials and other equipment. We recommend that the AESO weight the CC components based on 35% labor, 15% turbine, and 50% materials and other equipment. These weights are determined based on the relative contribution to plant capital costs due to each component.

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77 Statistics Canada, construction union wage rates including selected pay supplements, monthly, CANSIM Table 18-10-0046-01 (formerly CANSIM 327-0003), available at https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810004601.

78 Statistics Canada, gross national income and gross domestic income, indexes and related statistics, quarterly, gross final domestic expenditure, CANSIM Table 36-10-0105-01 (formerly CANSIM 380-0065), available at https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=3610010501.

79 FRED, Federal Reserve Bank of St. Louis, producer price index by industry: turbine and turbine generator set units manufacturing, available at https://fred.stlouisfed.org/series/PCU333611333611. Monthly average foreign exchange rates in Canadian dollars, Bank of Canada, CANSIM Table 33-10-0163-01 (formerly CANSIM 176-0081), available at https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=3310016301.

Table 17: Composite Index for Updating CONE

Component	Current Index	Aero CT	Frame CT	CC
Turbine	268.7	40%	30%	15%
Labor	60.7	25%	25%	35%
Materials	118.5	35%	45%	50%

Sources and notes:

[1]: The turbine index is the product of the monthly U.S. PPI index averaged over a 12-month period from June 2017 through May 2018 and the monthly CAD/USD foreign exchange rate averaged over the same 12-month period. The turbine index is indexed to June 1982 = 100.

[2]: The labor index is based on the 12-month average from June 2017 through May 2018. The labor index reflects wages in dollars and is not indexed to a particular year.

[3]: The materials index is based on the 4-quarters average from second quarter 2017 through first quarter 2018. It is indexed to 2007 = 100.

Under this approach, CONE values would be updated by multiplying the current CONE values by the changes in each component index, weighted by the technology-specific weights defined in Table 17 above. For example, the formula used for updating the current Aero CT CONE value of $244.2/kW-yr can be expressed by the equation below.

$$New\ Aero\ CT\ CONE\ = \$244.2 \times \left(40\% \times \frac{New\ Turbine\ Index}{268.7}\ +\ 25\% \times \frac{New\ Labor\ Index}{60.7}\ +\ 35\% \times \frac{New\ Materials\ Index}{118.5}\right)$$

As with the updates to CONE, the AESO may wish to update variable O&M estimates between the detailed CONE studies to be performed every four to five years. We recommend the AESO use changes in the Canadian gross domestic product (GDP) deflator, reported by Statistics Canada, to escalate variable O&M prior to each base auction. A large portion of variable O&M is related to maintenance costs specified in LTSAs, which have contract escalation formulas commonly tied to the consumer price index. The other major components of variable O&M are chemicals and consumables, which are commonly escalated by general inflation indices. Therefore, we recommend escalating variable O&M by the Canadian GDP deflator.

List of Acronyms

AB	Alberta
AB-NIT	Alberta NOVA Inventory Transfer
AEP	Alberta Environment and Parks
Aero CT	Aeroderivative Combustion Turbine
AESO	Alberta Electric System Operator
ASHRAE	American Society of Heating, Refrigerating, and Air-Conditioning Engineers
BLS	Bureau of Labor Statistics
CAD	Canadian Dollars
CAISO	California Independent System Operator
CAN	Canada
CAPM	Capital Asset Pricing Model
CC	Combined Cycle
CCA	Capital Cost Allowance
CMD	Comprehensive Market Design
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CoD	Cost of Debt
CoE	Cost of Equity
CONE	Cost of New Entry
CPI	Consumer Price Index
CRP	Country Risk Premium
CT	Combustion Turbine
CUWRI	Construction Union Wage Rate Index
DCF	Discounted Cash Flow
DCWG	Demand Curve Working Group
E&AS	Energy and Ancillary Service
ECAPM	Empirical Capital Asset Pricing Model
EPC	Engineering, Procurement, and Construction
ERCOT	Electric Reliability Council of Texas

Frame CT	Frame-Type Combustion Turbine
FT-D	Firm Transportation—Delivery
GDP	Gross Domestic Product
GDPD	Gross Domestic Product Deflator
GE	General Electric
GJ	Gigajoule
GST	Goods and Services Tax
GSU	Generation Step Up
GUOC	Generating Unit Owner's Contribution
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
HST	Harmonized Sales Tax
IC	Internal Combustion
ICAP	Installed Capacity
IDC	Interest During Construction
IPP	Independent Power Producer
IPPI	Industrial Product Price Index
IRR	Internal Rate of Return
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
ITC	Input Tax Credit
kJ	Kilojoule
kV	Kilovolt
kW	Kilowatt
kW-year	Kilowatt-Year
kWh	Kilowatt Hour
LFS	Labor Force Survey
LTA	Long-Term Adequacy
LTSA	Long-Term Service Agreement
MEPI	Machinery and Equipment Index
MISO	Midcontinent Independent System Operator

MMBtu	Million British Thermal Units
MRP	Market Risk Premium
MW	Megawatt
MWh	Megawatt Hour
NGTL	Nova Gas Transmission Ltd
NGX	Natural Gas Exchange
NOx	Nitrous Oxides
NPV	Net Present Value
NYISO	New York Independent System Operator
NYSE	New York Stock Exchange
O&M	Operation and Maintenance
OFE	Owner-Furnished Equipment
PPI	Producer Price Index
ppm	Parts Per Million
RICE	Reciprocating Internal Combustion Engine
RMPI	Raw Material Price Index
ROE	Return on Equity
S&L	Sargent & Lundy
S&P	Standard & Poor's
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SPRINT	Spray-Intercooling
UCAP	Unforced Capacity
USD	United States Dollars
WACC	Weighted Average Cost Of Capital

Appendix: Detailed Analysis of Specifications and Costs

A. Aeroderivative Turbine Power Augmentation Options

The standard LM6000 turbine experiences a significant derate to its net plant capacity during the summer months due to its sensitivity to inlet air temperature. Given the influence of summer capability on AESO's calculation of unforced capacity (UCAP), we believe a developer would pursue power augmentation options to abate the summer derate, if cost effective.[80] We considered four different power augmentation options for the Aero CT, which are presented in Table 18 below; we considered the addition of evaporative cooling, GE's SPRINT (Spray Intercooling) technology, both evaporative cooling and SPRINT, or neither.

Table 18: Aeroderivative CT Power Augmentation Options (2018 CAD)

Scenario	Net Plant Capacity		Overnight Cost (2018$)			Heat Rate	
	Winter MW	*Summer MW*	*$million*	*Winter $/kW*	*Summer $/kW*	*Winter kJ/kWh*	*Summer kJ/kWh*
Basic Aeroderivative CT	92.7	66.0	134.6	1,452	2,039	9,505	10,153
Aeroderivative CT + Evaporative Cooling	92.5	74.0	144.4	1,560	1,951	9,510	9,915
Aeroderivative CT + SPRINT	93.0	78.2	137.5	1,479	1,758	9,526	9,954
Aeroderivative CT + Evaporative Cooling + SPRINT	92.8	82.8	147.3	1,587	1,779	9,530	9,854

Sources and notes:
S&L proprietary database. Turbine costs also informed through discussion with vendors.

We evaluated the options based on the impact on plant capital costs and summer net plant capacity and found the addition of the SPRINT technology alone to be most cost effective. Compared with the base turbine, the SPRINT technology increases summer net plant capacity by 12.2 MW for only a $3 million increase in capital costs. On a per-kW basis, the SPRINT technology is marginally more expensive than the basic turbine in terms of winter capacity, but much less expensive (nearly $300/kW less) in terms of summer capacity.

Compared with evaporative cooling alone, the SPRINT technology is less expensive in absolute dollars and yields higher output in both seasons. While the combined inclusion of SPRINT technology and evaporative cooling yields a slightly higher summer output than the SPRINT technology alone, the additional costs are not justified and the SPRINT technology alone has more favorable costs on a per-kW basis in both seasons.

80 Unforced capacity (UCAP) calculations will depend on the 250 tightest supply cushion hours per year over the past five years, many of which occur in the summer months. See AESO (2018). CMD Final Proposal, Section 3: Calculation of Unforced Capacity (UCAP), p. 3, available at https://www.aeso.ca/assets/Uploads/CMD-4.0-Section-4-Calc-of-Demand-Curve-FINAL.pdf.

B. CONSTRUCTION LABOR COSTS

Labor costs are comprised of "construction labor" associated with the EPC scope of work and "other labor" that includes engineering, procurement, project services, construction management, field engineering, startup, and commissioning services.

S&L developed labor rates through a survey of prevalent wages in the Edmonton region in 2018, obtained from independent publications. Additionally, a local construction contractor and a local utility independently provided straight time burdened rates, including union and government burdens (Fringe Benefits, Worker's Compensation, Payroll Taxes) for craft Journeyman. The labor rates in this analysis primarily reflect unionized labor from the Edmonton labor pool. Table 19 shows the burdened craft rates used in the cost estimate.

Table 19: 2018 Edmonton Burdened Craft Rates ($/hr, CAD)

Craft Description	Hourly Labor Rate
Common Building Laborers	$49.49
Air Tool Laborers	$32.41
Asbestos/Insulation Workers/Pipe Coverers	$59.28
Boilermakers	$62.89
Bricklayers	$54.70
Carpenters	$58.04
Carpet & Linoleum Layers	$36.98
Cement Finishers	$57.04
Electricians	$64.30
Elevator Constructors	$76.65
Equipment Operators, Crane or Shovel	$61.86
Equipment Operators, Medium Equipment	$54.50
Equipment Operators, Light Equipment	$48.73
Equipment Operators, Oilers	$60.14
Equipment Operators, Master Mechanics	$57.55
Glaziers	$35.99
Lathers	$46.52
Helpers	$46.88
Millwrights	$63.64
Painters, Ordinary	$52.40
Painters, Spray	$51.79
Painters, Structural Steel	$57.29
Paper Hangers	$52.40
Pile Drivers	$32.29
Plasterers	$54.51
Helpers	$40.48
Pipefitters	$57.55
Helpers	$40.90
Rodmen (Reinforcing)	$54.55
Roofers	$48.50
Sheet Metal Workers	$61.33
Stone Masons	$46.43
Structural Steel Workers	$60.32
Welders, Structural Steel	$60.32
Truck Drivers, Light	$36.16
Truck Drivers, Heavy	$56.60

Sources and notes:
S&L Database.

Table 20 shows that the burdened labor rates for several crafts are similar to the labor rates reported by the Construction Labour Relations—Alberta (CLRA) and RSMeans.

Table 20: Summary of Select Craft Rates in Edmonton ($/hr, CAD)

Craft	Sargent & Lundy	CLRA	RSMeans
Millwright	$63.64	$60.15	$64.36
Pipefitters	$57.55	$59.92	$59.92
Carpenter	$58.04	$54.87	$54.87

Sources and notes:
S&L Database. Construction Labour Relations Wage Summary Construction—Alberta, available at https://clra.org/uploads/agreements/Wage%20Summary%20-%202016-06-01.pdf. Plotner, Stephen C. (2018). Building Construction Costs with RSMeans Data 2018, Gordian RSMeans Data.

The burdened craft rates are incorporated into work crew rates based on the required mix of construction activities for each plant type. Allowances for construction site overheads, such as small tools, construction equipment, insurance, payment bonds, and site overheads are then added to develop the detailed cost estimate. The total labor cost is based on a 5-day, 10-hour work week with a *per-diem* included to attract skilled labor.

Construction projects in Alberta face significant productivity challenges that can substantially increase labor costs. The factors that impact labor productivity include but are not limited to weather, overtime, fatigue, stacking of trades, availability of manpower, out of sequence work, and turnover. The construction of an aeroderivative unit is not very complex as there is minimal work outside of the installation of the combustion turbine. As a result these productivity challenges are less impactful and good labor productivity (1.15) is achievable. This has been demonstrated by recent builds in the province. Although there have not been many installations in the province, we assume a simple-cycle Frame CT machine would have the same labor productivity as an aeroderivative machine due to its similar level of complexity. In contrast, the installation of a CC is more complex with many different vendors and trades involved. The duration of a CC project is much longer thus the labor productivity factors listed would have a much larger impact on the labor force. Although there have been very few CC builds within the province, the productivity factors assumed for this study are supported by stakeholder input and discussions with developers participating in the capacity market design, as well as data published in the 2018 version of RSMeans. A summary of construction labor cost assumptions is shown below in Table 21.[81]

81 These values are less than the labor costs that appear in Table 8 since they are based on current 2018 labor rates. The labor costs in Table 8 have been escalated to reflect the expected labor costs during the construction period, assuming a November 1, 2021 commercial online date.

Table 21: Construction Labor Summary

	Aeroderivative CT	Frame CT	Combined Cycle
Construction Labor Hours	150,698	194,216	1,200,351
Productivity Factor	1.15	1.15	1.6
Weighted Average Labor Rate	$134.75	$135.58	$139.49
Construction Labor Cost	$20,306,000	$26,332,000	$167,439,000

Sources and notes:
S&L Database. Productivity factors are informed through discussion with developers in Alberta and data published in RSMeans. All monetary values are in 2018 CAD.

C. Net Startup Fuel Costs

We made the following assumptions to calculate net startup fuel costs:

- *Electric Energy*: estimate revenues from electricity sales during the testing periods using the estimated all-hours electricity futures for September and October 2021, based on the annual all-hours electricity futures price for 2021 and the monthly trend in all-hours electricity futures prices observed in 2019. .[82]
- *Natural Gas*: estimate fuel costs using the AB-NIT gas price forwards for September and October of 2021, as reported by NGX.

The gas futures prices reported by NGX are published in U.S. dollars, so we converted them to Canadian dollars using a forward exchange rate relevant to the September and October 2021 time period.[83]

Table 22: Startup Production and Fuel Consumption during Testing, 2021 CAD

	Energy Production			Fuel Consumption			
	Energy Produced	Energy Price	Energy Sales Credit	Natural Gas	Natural Gas Price	Natural Gas Cost	Total Cost
	MWh	*$/MWh*	*$million*	*GJ*	*$/GJ*	*$million*	*$million*
Aeroderivative CT	44,625	$46.15	$2.06	448,849	$1.79	$0.8	-$1.3
Frame CT	116,528	$46.15	$5.38	1,243,797	$1.79	$2.2	-$3.2
Combined Cycle	412,210	$46.15	$19.02	3,038,410	$1.79	$5.4	-$13.6

Sources and notes:
Energy production and fuel consumption estimated by S&L. Energy prices from NGX as of 5/8/2018. Gas prices from NGX as of 4/25/2018.

82 The most future year with electricity futures reported at the monthly level is 2019; beyond 2019, electricity futures are presented at the annual level.

83 We sourced forward exchange rates from CME Group, as reported July 6, 2018, available at https://www.cmegroup.com/trading/fx/g10/canadian-dollar_quotes_globex.html.

D. GAS AND ELECTRIC INTERCONNECTION COSTS

We compiled a sample of TransCanada's publicly-available gas lateral projects and their associated costs to inform a reasonable estimate for gas interconnection costs. We filtered the sample such that pipe diameter was less than or equal to 24 inches and pipe length was less than or equal to 20 km. We then calculated the average per-kilometer costs of the laterals ($3.3 million/kilometer). The summary of project costs and the average per-kilometer pipeline cost are shown in Table 23. The costs represented in Table 23 reflect the costs for NGTL to build the lateral. NGTL recommended that we consider the Stoney Transit/North Gas Connection Piping project to be the most representative of the costs for a short gas lateral to a new generation plant. In addition, we assume that a merchant developer is likely to build the lateral on their own at a slight discount to what NGTL could build the lateral. Based on these considerations, we assume that the costs for a merchant developer to build the interconnecting gas lateral are $2 million/kilometer.

Table 23: Representative Gas Lateral Project Costs, CAD

Pipeline Project	Pipe OD	Pipe Length	Project Cost	
	Inches	*km*	*$million*	*$million/km*
Hythe Lateral Loop No. 2	20	13	$41	$3.1
Cutbank River Lateral Loop No.2	24	18	$65	$3.6
Calgary UPR (AP)	20	19	$88	$4.6
Edmonton APR (AP)	20	8	$34	$4.2
Inland Looping (AP)	20	19	$42	$2.2
Kettle River Lateral Loop	24	20	$75	$3.7
Pembina Expansion	24	20	$66	$3.2
McDermott Extension	20	8	$44	$5.5
Stoney Transit/North Gate Connection Piping	8	4	$8	$1.9
Worsley McLennan Transmission Loop	6	11	$8	$0.7
Average				**$3.3**

Sources and notes:
Recent gas lateral projects were identified based on the TransCanada 2017 Annual Plan and the GPMi Alberta Gas Supply and Infrastructure Analysis Report. Projects have in-service dates from 2016 to 2019.

Table 24 below summarizes the average electrical interconnection costs of recently installed generation resources in Alberta that we identified as representative of the CT and CC reference resources. We selected the sample of 19 recent generation projects (2,894 MW of total capacity) by excluding projects that did not include a transmission line, had total costs over $200,000/MW, or where the transmission lines were over 12 kilometers long.[84] The costs are based on confidential, project-specific cost data provided by AESO for only the direct connection

[84] The sample includes 6 gas plants, 11 wind plants, a coal plant, and a cogeneration plant. We found that the average interconnection costs for the wind plants on a per-kW basis were similar to the fossil fuel-fired plants.

facilities.[85] We adjusted the costs to 2018 dollars based on the assumed long-term escalation rate for materials of 2.0% (see Table 9 above), assuming the costs were incurred as of the online service dates.[86] We then calculated the capacity-weighted average interconnection costs. We used the capacity-weighted average of $58.3/kW (in 2018 dollars) across all representative plants for estimating the electrical interconnection costs of the reference resources.

Table 24: Electric Interconnection Costs in AESO, CAD

Plant Size	Observations	Electrical Interconnection Cost Capacity Weighted Average	
	Count	*2018 $million*	*2018$/kW*
< 100 MW	9	$3.4	$50.3
100 - 200 MW	7	$11.0	$68.8
> 200 MW	3	$23.3	$52.5
Capacity Weighted Average	**19**	**$15.0**	**$58.3**

Sources and notes:
Confidential project-specific cost data provided by AESO.

E. Land Costs

We estimated the cost of land in the counties surrounding Edmonton by reviewing current asking prices for vacant industrial land greater than or equal to 10 acres for sale. We then calculated the acre-weighted average land price as shown in Table 25.

Table 25: Current Land Asking Prices (Millions, CAD)

County	Observation 1		Observation 2		Observation 3		Total		
	Price	*Acres*	*Price*	*Acres*	*Price*	*Acres*	*Price*	*Acres*	*$/Acre*
Parkland County	$11.5	119.0	$1.9	21.0			$13	140.0	$95,742
Sturgeon County	$3.5	76.8	$17.0	158.5	$8.3	137.8	$29	373.1	$76,981
Leduc County	$14.7	141.4	$14.7	150.0	$16.3	41.3	$46	332.7	$137,440
Stratchcona County	$9.1	83.0					$9	83.0	$110,000
Total							**$97**	**928.8**	**$104,415**

Sources and notes:

85 This database did not include costs related to any necessary network upgrades, which would be socialized by the AESO and thus are not costs for which the generator is responsible. They do not include "inside the fence" costs. The transmission costs are pulled from the same database as the one posted on the AESO website concerning transmission costs (https://www.aeso.ca/grid/transmission-costs/). However the publicly-available database does not identify the specific project associated with each entry.

86 Our sample includes connection cost estimates for both existing and proposed facilities. There are 8 existing projects in our sample and 11 that are proposed or under construction.

Prices are in millions except for the final $/acre amount. No prices were available for Fort Saskatchewan. We pulled land listing prices on April 12, 2018 from LoopNet's Commercial Real Estate Listings (www.loopnet.com)

We calculated the total cost of land for each technology in Table 26, assuming 10 acres for the Aero CT and Frame CT and 30 acres for the CC.

Table 26: Cost of Land Purchased (CAD)

Criteria	Units	Aeroderivative CT	Frame CT	Combined Cycle
Plot Size	*acres*	10	10	30
Land Price	*$/acre*	$104,415	$104,415	$104,415
Cost	*$million*	$1.04	$1.04	$3.13

Sources and notes:
We assume land is bought in 2018.

F. PROPERTY TAXES

We researched property tax rates in five counties surrounding Edmonton: Fort Saskatchewan, Leduc County, Parkland County, Strathcona County, and Sturgeon County. The rates we used are listed in Table 27. In Alberta, the assessable, non-land costs of electric power generation facilities are exempt from the provincial education tax. Thus, the assessable plant costs are taxed at 0.87% based on the average across the five counties. Assessable plant costs were determined based on Alberta's Construction Cost Reporting Guide.[87] Land value is not exempt from the education tax, so land costs are taxed at the higher rate of 1.24%.

[87] Alberta Government (2017). 2005 Alberta Construction Cost Reporting Guide, effective for 2017 assessment year, available at https://open.alberta.ca/dataset/8748ab7a-b0f5-4c5a-9cf3-6744d64a5516/resource/1d54ea3e-8650-43e2-9124-8590af481d1b/download/2005-alberta-construction-cost-reporting-guide-2017.pdf. It is our understanding that Alberta's Construction Cost Reporting Guidelines are under negotiation and the costs deemed assessable may change. At the time of this study, we do not have any information as to how the assessable costs might change and thus estimate property taxes based on the current guidelines. Plant costs that have been excluded from assessable value include project development, mobilization & startup, net startup fuel costs, non-fuel inventories, financing fees, and interest during construction (IDC).

Table 27: Property Tax Rate Estimates

County		Real Property Tax Rate	Other Property Tax Rate
Fort Saskatchewan	[1]	1.29%	0.91%
Leduc County	[2]	1.07%	0.69%
Parkland County	[3]	1.18%	0.80%
Strathcona County	[4]	1.28%	0.91%
Sturgeon County	[5]	1.40%	1.05%
Average		**1.24%**	**0.87%**

Sources and notes:
[1]: City of Fort Saskatchewan: Property Tax and Supplementary Property Tax Bylaw C15-18
[2]: Leduc County Bylaw No. 17-18
[3]: Parkland County Bylaw 2018-08
[4]: Strathcona County Bylaw #20-2018, Schedule "A"
[5]: Sturgeon County 2018 Taxation Rates, Bylaw 1406/18

We computed the assessable value for property taxes using the formula prescribed in the 2017 Alberta Linear Property Assessment Minister's Guidelines.[88] The formula incorporates assessable costs and resource-specific depreciation schedules as well as an "assessment year modifier" and "cost factor," which account for the vintage of assessable costs and the particular tax assessment year.[89] For the Aero CT, we use a depreciation schedule applicable to generic power generation with units between 1 and 50 MW in size.[90] For the Frame CT and the Combined Cycle, we use the depreciation schedule applicable to units with capacity in excess of 100 MW.[91]

The current guidelines contain only assessment year modifiers and cost factors through 2017. To estimate assessable value as of 2021, the first assessment year for the reference facilities, we took a linear trend of the assessment year modifiers and cost factors over the most recent five years

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88 Alberta Government (2017). 2017 Alberta Linear Property Assessment Minister's Guidelines, effective for 2017 assessment year, p. 4, Section 2.004, available at https://open.alberta.ca/dataset/6c713b0e-1c8a-4d5a-926f-89c3e07f5d6b/resource/604b62d4-b167-466e-a8fe-d858b48bb721/download/2017-alberta-linear-property-assessment-ministers-guidelines.pdf.

89 As with the cost reporting guidelines, we understand that Alberta's property tax depreciation schedules are currently being evaluated and may change. At the time of this study, we do not have any information as to how the schedules might change and thus estimate property taxes based on the current guidelines.

90 *Id.*, p. 16, see "GEN300" in Table 2.01, and p. 30, Column 1 of Table 2.28. Note that the total capacity of the 2×0 Aero CT exceeds 50 MW, but each individual unit is less than 50 MW.

91 *Id.*, p. 16, see "GEN302" in Table 2.01, and pp. 39-40, Column 1 of Table 2.30.

and extrapolated to 2021 values.[92] For the years following 2021, we assume assessable costs increase annually with inflation and strictly apply the relevant depreciation schedule.[93]

G. Firm Gas Contracts

NGTL requires a new facility interconnecting with their system in a demand-constrained region to sign a contract for firm service with an initial term of eight years. For the initial eight-year contracts, we obtain firm transportation service rates from NGTL's FT-D tariff and apply the 10% discount applicable to contracts of five years in length (or longer).[94] We account for the 2021 online date by escalating the tariff rates as of 2018 by three years at 2.0% per year, using the materials escalation rate shown in Table 9 above.

NGTL requires new facilities to obtain minimum capacity levels for firm service based on expected peak operations. We estimated the assumed minimum capacity levels in consultation with NGTL based on the reference resource specifications and operational assumptions developed through discussions with the AESO. Table 28 shows the calculation for the annual costs of firm gas transportation service during the initial eight-year term. We assume the CC runs at full capacity with duct firing during on-peak hours, and runs at full capacity less duct firing in off-peak hours. We assume the Aero CT runs at full capacity in all hours. Both the CC and the Aero CT sign firm service contracts for capacities that equal their expected daily gas requirements. To respect the 33% capacity factor restriction due to environmental regulations, we assume the Frame CT runs only during on-peak hours, but at full capacity. The Frame CT's initial contract capacity is the minimum required by NGTL, which exceeds the Frame CT's expected daily gas requirement.

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92 *Id.*, p. 3, Table 1.10, and p. 18, Table 2.02.

93 We reviewed and confirmed this methodology as reasonable with a member of Alberta's Linear Property Assessment Unit.

94 See NOVA Gas Transmission Ltd., Table of Rates, Tolls and Charges, effective May 1, 2018, for Group 2 Delivery Points (industrial customers), available at http://www.tccustomerexpress.com/docs/ab_regulatory_tariff/08%202018%20Interim%20-%20Table%20of%20Rates%20May%201%202018.pdf; and NOVA Gas Transmission Ltd., Rate Schedule FT-D, Firm Transportation – Delivery, Section 3 (Pricing), available at http://www.tccustomerexpress.com/docs/ab_regulatory_tariff/ngtl-rate-schedule-ft-d.pdf.

Table 28: Estimated Annual Cost of Firm Gas Transportation for the Initial 8-Year Term

Component		Units	Aero CT	Frame CT	CC
Net Winter Capacity (w/o duct firing)	[1]	*MW*	93	243	429
Net Winter Capacity (w/ duct firing)	[2]	*MW*	93	243	479
Net Winter Heat Rate (w/o duct firing)	[3]	*kJ/kWh, HHV*	9,526	10,109	6,981
Net Winter Heat Rate (w/ duct firing)	[4]	*kJ/kWh, HHV*	9,526	10,109	7,163
Maximum Hourly Consumption	[5]	*GJ/hr*	886	2,454	3,431
Maximum Daily Consumption	[6]	*GJ/d*	21,255	58,899	82,355
Implied Minimum Monthly Contract	[7]	*GJ/d*	19,000	38,000	75,000
Hours of Baseload Consumption	[8]	*hr/d*	24	8	16
Hours of Ducts Consumption (if applicable)	[9]	*hr/d*	0	0	8
Expected Daily Consumption	[10]	*GJ/d*	21,000	20,000	75,000
Contracted Monthly Firm Gas Capacity Reservation	[11]	*GJ/d*	21,000	38,000	75,000
Cost of Monthly Firm Gas Reservation	[12]	*$ per GJ/d*	$4.766	$4.766	$4.766
Total Cost of Monthly Firm Gas Reservation	[13]	*$ per month*	$100,084	$181,104	$357,441
Total Annual Cost of Firm Gas Reservation	[14]	***$ per year***	**$1,201,003**	**$2,173,244**	**$4,289,297**
Total Annual Cost of Firm Gas Reservation	[15]	*$/kW per year*	$12.92	$8.95	$8.95

Sources and notes:

[1]–[4]: See Tables 3–5

[5]: [2] × [4] / 1,000

[6]: [5] × 24

[7]: Provided by NGTL

[8]–[9]: Brattle assumption

[10]: ([1] × [3] × [8] + [2] × [4] × [9]) / 1,000

[11]: Maximum of [7] & [10]

[12]: NGTL tariff (effective May 1, 2018), adjusted for term-length discount and escalated to 2021

[13]: [11] × [12]

[14]: [13] × 12

[15]: [14] / [2] / 1,000

After the initial eight-year term, we assume the Frame CT will reduce its contract capacity to its expected daily gas requirement and renew annually. Given the certainty implicit in the baseload operations assumption, the CC and the Aero CT will continue to obtain capacity to serve their entire daily requirement and will renew every five years in order to lock-in prices and obtain the discount. We assume the contracted rate at renewal is the 2018 NGTL rate escalated at inflation annually (2.0%).

H. Summary of Additional Plant Cost Assumptions

Table 29 below summarizes the plant capital cost assumptions described in detail in Section IV.

Table 29: Detailed Cost Assumptions

Cost Category	Unit	CT	CC
EPC Contractor Fee	% of other EPC costs	6%	10%
EPC Contingency	% of other EPC costs	8%	10%
Project Development Cost	% of EPC costs	5%	5%
Mobilization and Start-Up Cost	% of EPC costs	1%	1%
Non-Fuel Inventories	% of EPC costs	2%	2%
Owner Contingency	% of other Owner's costs	8%	8%
Financing Fees	% of debt-financed EPC and non-EPC costs	4%	4%
Construction Debt Financing	Debt-financed % of EPC and non-EPC costs	50%	50%
Insurance	% of overnight capital costs per year	0.6%	0.6%

Sources and notes:
The non-fuel inventories value of 2% consists of 0.5% for consumables and spare parts and 1.5% for financial working capital requirements. EPC costs include owner furnished equipment.

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