Q. With reference to Technical Workshop presentation slide 24 (pdf page 24 of 37):

Please provide the 2021 Marginal Cost Study update completed for Hydro by CA Energy, as referenced in the Technical Workshop presentation slide 24.

A. Please refer to TC-IC-NLH-001, Attachment 1.

Marginal Cost Study Update – 2021

Summary Report

March 7, 2022

A report to the Board of Commissioners of Public Utilities

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List of Appendices

1.0 Background

In 2021, Newfoundland and Labrador Hydro ("Hydro") engaged Christensen Associates Energy Consulting, LLC ("CA Energy Consulting") to develop and provide an update of its 2018 Marginal Cost Study.

The methodology used to produce the 2021 Marginal Cost Study is consistent with the approach used in the 2018 Marginal Cost Study, previously filed with the Board of Commissioners of Public Utilities ("Board"). The 2021 update reflects revised load forecasts, revisions to the source of the next marginal unit, the timing of generation additions to and retirements from Hydro's Island Interconnected System (including in-service of the Labrador-Island Link ("LIL") and the Muskrat Falls generating assets), and the forecasted netback market prices.[1]

This 2021 Marginal Cost Study Update provides the estimated generation and transmission marginal costs for the period 2023–2040. In addition to this summary report, Hydro is filing the results of the 2021 Marginal Cost Study and a Technical Brief by CA Energy Consulting, included as Appendix A and B to this summary report, respectively. This information is provided to assist the Board and parties in further understanding the marginal cost estimates, their use for system planning and their potential use in electrification and conservation and demand management.

2.0 Key Assumptions

The 2021 Marginal Cost Study was based on a number of underlying assumptions about Hydro's system configuration and planning criteria. Throughout the past number of years, several of these fundamental assumptions have changed and have had implications on the resulting marginal costs. Consequently, Hydro's projected marginal costs have changed from those presented in the 2018 Marginal Cost Study. This section summarizes the key assumptions for the 2021 Marginal Cost Study Update.

2.1 Load Forecast

The underlying load forecast in this 2021 Marginal Cost Study Update shows an increase in Island Interconnected load throughout the next decade, with demand projected to grow by 99 MW

[1] Forecast external market prices are used to determine opportunity costs.

(cumulative growth of 6%) and energy requirements expected to grow by 589 GWh (cumulative growth of 7%).

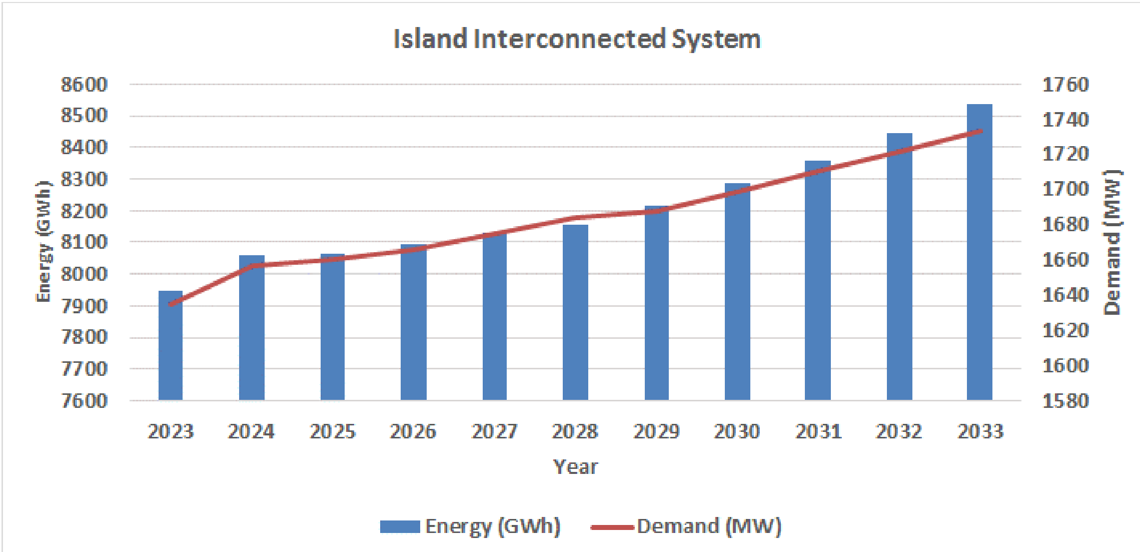


Chart 1: Projected Island Interconnected Load 2023 vs. 2033

The load growth is partly a reflection of an increase in electrification including electric vehicles ("EV") and general customer load growth. Load growth associated with EVs is projected to continue to grow, reaching 22 MW of demand and 288 GWh of energy by 2033. This is an increase from the load growth associated with EVs included in the forecast used in the development of Hydro's 2018 Marginal Cost Study. Hydro's most recent load forecast assumes a 2022 mitigated rate of 14.7¢/kWh in 2022 for residential customers, escalated by 2.25% annually thereafter.[2] This reflects a lower residential rate than the 17¢/kWh used in the development of the 2018 Marginal Cost Study, contributing to an increase in expected demand and energy requirements.

2.2 System Expansion and Marginal Generation Capacity Costs

Throughout the next several years, Hydro's Island Interconnected System will experience significant change. Hydro anticipates the retirement of the Holyrood Thermal Generating Station ("Holyrood TGS"), as well at the gas turbines at Hardwoods and Stephenville following the in-service of the LIL and Muskrat

[2] The 14.7 ¢/kWh price is consistent with the Agreement in Principle on rate mitigation between the Government of Newfoundland and Labrador's and Canada.

Falls Generating Station. With the additional load growth from electrification, current projections would require incremental resource additions to be in-service by 2033. Consistent with the results of the 2019 Update to the Reliability and Resource Adequacy Study, construction of Unit 8 at the Bay d'Espoir Generating Station ("BDE 8") has been identified as the least-cost resource option. This differs from information used in the 2018 Marginal Cost Update, which included construction of two 58.5 MW single cycle combustion turbines.

2.3 Marginal Generation Energy Costs

Hydro's marginal generation energy costs have historically been determined using internal production costs. That is, the variable costs associated with operating the Holyrood TGS to provide energy. However, Newfoundland and Labrador is now interconnected to the North American grid. This provides Hydro the ability to import energy from, and sell energy to, other jurisdictions. Therefore, opportunity costs are the best measurement of Hydro's marginal energy costs going forward. Similar to the 2018 Marginal Cost Study, marginal energy costs in this update continue to use an external price forecast for the ISO-NE[3] market. As part of the 2021 Marginal Cost Study, opportunity costs have been updated to reflect new external market transmission losses and the inclusion of external market transmission tariff costs, which provides a more accurate representation of the netback value of export transactions.

3.0 Estimated Marginal Costs

For the years 2023–2040, all-in marginal costs[4] are linked to the forecasted system loss of load hours. For the years 2023–2026, marginal costs are increased compared to subsequent years, reflecting a declining forced outage rate for the LIL as this asset enters service. This approach is consistent with that used in Hydro's Near-term Reliability Reports, filed semi-annually with the Board. Through these years, marginal costs decline as the reliability of the LIL continues to improve until the LIL is assumed to meet its design reliability in 2026. The marginal costs then begin to increase as load increases for the period from 2027–2032. The assumed addition of BDE 8 to ensure sufficient reliability given forecast system demand growth results in a lower marginal cost in 2033. Following the addition of BDE 8, marginal cost continue to increase as demand grows.

[3] ISO New England ("ISO-NE").
[4] All-in marginal costs include energy, operating reserves, and generation and transmission capacity.

3.1 Seasonal Marginal Cost Patterns

On a seasonal basis, consistent with the results of the 2018 Marginal Cost Study, system marginal costs continue to be materially higher in the winter than during the non-winter months, and also vary materially by time of day (i.e. on-peak marginal costs are higher than off-peak marginal costs).

Table 1 shows Hydro's 2024 estimated marginal cost by component for the Island Interconnected System for the winter and non-winter periods.

Table 1: Hydro's 2024 Island Interconnected System Marginal Costs by Season (¢/kWh)

	Generation Energy	Generation Capacity	Transmission Generation and Capacity	All-in Marginal Costs
Winter	5.5	10.9	1.3	17.7
Non-Winter	1.4	0.2	0.0	1.6

As shown in Table 1, the average winter marginal cost is estimated to be 17.7¢/kWh. The average marginal cost for the non-winter period is estimated to be 1.6 ¢/kWh, or approximately 1/10th of the winter marginal cost. The difference in winter and non-winter marginal costs is disproportionately larger than the difference in winter and non-winter peak loads.

The disparity in marginal capacity costs between winter and non-winter seasons is largely related to generation capacity costs, which occur primarily in the winter months. This is because Hydro's system is designed to accommodate its peak load, which occurs in the winter, with limited capacity available to serve additional loads during that period. As such, additional investment to supply increases in customer peak demand requirements would only be required during the winter period. During non-winter periods, Hydro has adequate capacity to serve incremental demand. Therefore, the marginal cost associated with a change in load during non-winter periods is negligible.

4.0 Conclusion

For the period of 2023–2040, Hydro is forecasting to have limited capacity available to serve additional customer load requirements during the winter period. As such, Hydro's marginal costs continue to be materially higher in the winter than in non-winter months.

Consistent with the results of the 2019 Update to the Reliability and Resource Adequacy Study, construction of BDE 8 has been identified as the least-cost resource option once a resource addition is required to satisfy system reliability requirements.

The results of the 2021 Marginal Cost Study Update, included as Appendix A, provides the results of Hydro's 2021 Marginal Cost Study. Appendix B, prepared by CA Energy Consulting, provides a detailed explanation of the updates incorporated into Hydro's marginal costs framework and model, as developed by CA Energy Consulting in support of the 2018 Marginal Cost Study. The updated marginal cost information provided in this Marginal Cost Study Update will assist Hydro, Newfoundland Power Inc., and stakeholders in assessing investments in customer demand management programs, smart metering and rate design options, and generation/transmission infrastructure.

Appendix A

Results Marginal Cost Study Update – 2021

Preliminary Marginal Cost Projection at 2021 for 2023 - 2040
Island Interconnected System

Energy Supply Costs					
	Winter		Winter	Summer	Annual
	On-Peak	Off-Peak	All-Hours	All-Hours	All-Hours
Year	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
2023	62.65	49.37	55.34	16.69	29.50
2024	60.96	49.30	54.54	15.75	28.61
2025	55.59	46.74	50.72	15.29	27.03
2026	51.62	43.91	47.37	15.28	25.92
2027	50.99	43.13	46.66	15.58	25.88
2028	49.83	43.06	46.10	16.06	26.02
2029	52.06	44.84	48.08	18.04	28.00
2030	51.55	45.13	48.01	17.02	27.29
2031	47.05	40.47	43.43	16.33	25.31
2032	45.05	39.51	42.00	15.80	24.49
2033	45.60	39.01	41.97	14.64	23.70
2034	40.51	36.38	38.24	13.30	21.57
2035	41.40	35.70	38.26	13.77	21.89
2036	35.58	32.16	33.70	12.21	19.33
2037	36.25	31.30	33.52	10.99	18.46
2038	36.38	33.77	34.94	11.51	19.28
2039	34.41	30.62	32.32	10.34	17.62
2040	33.27	32.07	32.61	9.81	17.37

Capacity Costs			
	Generation	Transmission	G&T
Year	$/kW	$/kW	$/kW
2023	300.15	38.38	338.53
2024	332.73	39.23	371.96
2025	215.05	40.10	255.14
2026	185.73	40.98	226.71
2027	200.90	41.89	242.79
2028	217.32	42.81	260.14
2029	235.09	43.76	278.85
2030	253.63	44.72	298.35
2031	281.04	45.71	326.75
2032	311.42	46.72	358.14
2033	179.46	47.76	227.22
2034	189.93	48.82	238.75
2035	201.01	49.90	250.91
2036	212.74	51.00	263.74
2037	225.15	52.13	277.28
2038	236.11	53.29	289.40
2039	247.61	54.47	302.07
2040	259.66	55.68	315.34

Notes:

Basis of Energy, Generation Capacity and Transmission Capacity is NLHydro's Marginal Cost update- Janaury 2022
Winter Season defined as December through March.
On peak Hours Winter 7:00 a.m. to 10:00 p.m., Monday through Friday
On peak Hours Summer 8:00 a.m. to 10:00 p.m., Monday through Friday

Appendix B

Marginal Cost Study Update – 2021

TECHNICAL BRIEF

MARGINAL COST OF ELECTRICITY SERVICES:
UPDATES INCORPORATED INTO
NEWFOUNDLAND AND LABRADOR HYDRO'S FRAMEWORK AND MODEL

prepared for
NEWFOUNDLAND AND LABRADOR HYDRO

prepared by
Robert J. Camfield
Nicholas A. Crowley
CHRISTENSEN ASSOCIATES ENERGY CONSULTING

***January 18*, 2022**

INTRODUCTION

The following discussion reviews recent developments in Newfoundland and Labrador Hydro's (Hydro) methodology for estimating forward-looking marginal costs of generation and transmission (G&T) services. Hydro's framework for estimating the marginal costs of G&T services of the Island Interconnected System (IIS) was set forth in reports filed by Hydro with the Board of Commissioners of Public Utilities (Board) during early 2016 and late 2018.[1] The framework is comprised of several cost components, as follows:

- *For generation services*: energy, operating reserves, and capacity costs;
- *For transmission services*: transport services (path charges including line losses and reservation fees) and capacity costs.

Marginal cost—also referred to as *avoided cost* or *incremental cost*—is the change in the total cost of electricity services associated with a change in the level of services provided. Hydro's projections of marginal costs are forward-looking over the long term and can serve as the benchmark to assess the net benefits which arise from a broad array of programs, activities, decisions, and commitments by stakeholders in retail electricity markets. Changes in electricity services provided—e.g., higher peak loads

[1] Reference MARGINAL COST REPORT, PART I, *Methodology:* Estimation of Marginal Costs of Generation and Transmission Services for 2019, December 29, 2015; MARGINAL COST REPORT, PART II, *Estimation:* Marginal Costs of Generation and Transmission Services for 2019, February 26, 2016; MARGINAL COST STUDY UPDATE – 2018, *Cost Estimates and Methodology* for Generation and Transmission Services, 2021-2029, November 15, 2019. Reports were prepared by Christensen Associates Energy Consulting for Hydro.

because of unusually cold weather, reduced peak loads arising from customer response to demand response programs, or greater usage due to increases in the number of customers served—have corresponding cost impacts, up or down. Viewed broadly, estimates of marginal cost are fundamental to electricity service providers such as Hydro.[2]

Hydro's framework for marginal costs is implemented in hourly frequency, covering forward years 2023-2040. Key features include:

- Energy and operating reserves based on opportunity cost: energy and reserve projections of market prices for Northeast wholesale markets (ISO New England);
- Generation capacity cost based on Hydro's least cost generation expansion plan; and,
- Transmission capacity costs based on Hydro's load-related capital expenditures, as planned for near-term years.

The original framework has evolved since 2016. The most notable change in methodology is the subject of this brief: integration of capacity cost estimates and expansion plans, where explicit measures of system reliability are used to determine marginal generation capacity costs.

HYDRO'S MARGINAL COST METHODOLOGY

Hydro's marginal cost methodology for generation services assumes an opportunity cost approach for energy and operating reserves. Marginal generation capacity costs, on the other hand, are based on Hydro's internal costs of installing incremental capacity, necessary to satisfy reliability standards in the face of changes in expected peak loads. Marginal transmission costs include transport path charges, which consist of energy losses and reservation fees associated with Hydro's use of the wholesale transmission facilities operated by NB Power, Nova Scotia Power, and Maritime Link.[3] Similar to generation, transmission capacity costs are based on estimates of the annual costs associated with Hydro's investment in transmission facilities to serve the expected rise in peak loads over several forward years, while also satisfying reliability standards.

[2] Estimates of marginal costs may inform investment decisions for a wide range of consumer groups: industrial consumers considering investment in high productivity automation; residential consumers looking into home improvements; and demand- and supply-side resource change influences such as tariff design options, conservation programs, and gains in system-wide efficiency. In all cases, the decisions involve resource commitments that have long-term electricity cost impacts.

[3] Hydro is actively involved in Northeast wholesale electricity markets. Most transactions are short-term power sales into ISO New England, facilitated by the transmission path stretching from Hydro's interconnection with the Maritime Link DC facility, through the AC bulk power networks of Novia Scotia Power and NB Power, to the Salisbury interconnection with the wholesale markets operated by ISO New England.

Both generation and transmission capacity costs can be viewed as proxies, or shadow prices, for the underlying reliability realized by electricity consumers. Stated generally, Hydro's framework for the marginal cost of G&T services of the Island Interconnected System is as follows:

$$Marginal\ Cost_{G\&T} = MEC * (Line\ Losses + Reservation\ Fees) + Generation_{Capacity} + Transmission_{Capacity}$$

where,

$$MEC = marginal\ energy\ \ and\ operating\ reserves\ cost$$
$$Generation_{Capacity} = Hydro's\ internal\ cost\ of\ capacity, as\ a\ proxy\ for\ reliability$$
$$Transmission_{Capacity} = \text{Hydro}'s transmission\ capacity\ costs$$

Generation capacity costs are stated as \$/kW-year[4] and are a function of expected peak loads, on the margin. The causal relationship between capacity costs and peak loads is measured by Loss of Load Hours (LOLH),[5] estimated monthly for selected analysis years[6] over the inclusive 20-year planning period, 2023-2040.[7] Generation capacity costs are incurred during the high load hours of LOLH months. Because of major differences in system load levels between high load winter months and off-peak seasons, off-peak months have virtually no generation capacity costs, on the margin. Similarly, transmission capacity costs

[4] The \$/kW-year cost estimates for generation and transmission capacity assume an *all-in* cost approach, and incorporate several cost elements and is specified as follows:

$$Capacity\ Cost = (I_{Direct} + I_{M\&S} + wk) * ECC_D + I_{Indirect} * ECC_{ID} + OM_{CT} + A\&G_{wrt\ OM} + Ins_{I,Ops}$$

where I_{Direct} *= facility investment expenditures,* $I_{M\&S}$ *= materials and supplies inventory, wk = working capital,* $I_{Indirect}$ *= indirect investment expenditures associated with facilities,* $ECC_{D,\ ID}$ *= economic carrying charge rates for direct or indirect investment expenditures, OM = operating and maintenance expenditures, A&G = annual administrative and general overheads, and Ins = annual insurance expenses*.

Economic Carrying Charge refers to the annual "all-in" carrying charges on investment expenditures for incremental capacity. ECC covers capital depletion, payback of principal, interest charges, corporate income taxes where appropriate, and return on equity capital including investor perceptions of risk. The ECC rate can be calculated as:

$$ECC = [\ (k - i + t) * (1 + i - t)^n / (1 + k)^n] * [(1 + k)^m / ((1 + k)^m - (1 + i - t)^m)]$$

where *k = capital charge rate*, *i = expected inflation*, *t = rate of technological advance*, *n = year*, and *m = expected life of capital*.

[5] Estimates of Loss of Load Hours closely parallels Expected Unserved Energy, generally speaking.

[6] Analysis years include 2022-2026, 2029, 2033, 2037, and 2040.

[7] Marginal costs are estimated for years 2023-2040.

are also stated as $/kW-year and, following the principle of causality, are incurred predominantly during high load hours of the winter peak season.[8]

In summary, Hydro's marginal cost methodology is fully consistent with well-accepted, contemporary marginal cost methodology. Key features include:

- Engagement with competitive wholesale markets in the Northeast region provides the basis for determining marginal energy and operating reserve costs. This opportunity cost approach yields the highest valued use of Hydro's generation and transmission resources. Subject to key constraints, including sustaining reliability within the IIS and adhering to transmission flow limits, Hydro will sell power into ISO New England markets, provided its internal marginal costs are less than the market price of energy.
- Alignment with Hydro's G&T expansion plans over future years implies that conservation and demand management programs and related activities of stakeholders can be explicitly benchmarked to resource value and worth over future periods. In collaboration with stakeholders, Hydro is well positioned to develop and implement demand response tariff options, where the end result is net gains in resource efficiency: higher energy consumption during low-cost off-peak hours, and lower consumption during high-cost peak hours and seasons.

METHODOLOGY CHANGE: EXPLICIT INCORPORATION OF RELIABILITY METRICS

Hydro's marginal cost model incorporates three methodology options for determining annual marginal generation capacity costs: internal cost of incremental generating capacity; simulation of system reliability; and the attenuation of internal capacity costs. Under the *internal cost* approach, the annual capacity costs ($/kW-year) are based on Hydro's projections of the all-in cost of installing capacity.[8]

The *system reliability methodology* utilizes estimates of loss of load hours (LOLH). LOLH refers to the number of hours in which total supply is less than total demand, averaged across numerous simulations of possible peak load levels and total system supply.[9] LOLH and related metrics[10] capture the likelihood that total load will not be served. LOLH is estimated monthly for selected analysis years over 2022-2040 using generation planning software (PLEXOS). Properly executed, analysis based on LOLH provides the

[8] As discussion in Hydro's marginal cost reports, as filed before the Board, the causal relationship between capacity costs and loads can be expressed using three methods. Hydro's current marginal cost framework employs a parameterized non-linear max function.

[9] Conditions for potential LOLH events, including possible levels of demand and supply over future years, are drawn randomly from the statistical distribution of forecast demand and generator unit availability.

[10] Other well-known metrics include *Loss of Load Expectation* (LOLE), *Loss of Load Probability* (LOLP), and *Expected Unserved Energy* (EUE).

means to estimate system reliability and, as a consequence, provides the means to determine the schedule for capacity additions.

The *attenuation approach* projects marginal generation capacity costs based on an algorithm, as applied to estimates of system reliability (LOLH) for defined analysis years. In essence, the attenuation approach mitigates the amplitude of the large year-over-year differences in estimates of system reliability. Whereas all-in installed costs of capacity may not vary dramatically, variation in estimates of system reliability may be an order of magnitude greater—system reliability can vary by a factor of 15-20 times across adjacent years. In moderate-sized systems, large variation in estimated—and realized—system reliability is a result of capital indivisibility. The build-out of conventional generating technologies is carried out in sizable increments in order to take advantage of the inherent economies of scale with larger unit additions.[11] The end result is lower average costs stated on a $/kW basis. However, sizable additions contribute to differences in system reliability across years, as supply-demand balance abruptly changes: a condition of capacity short can switch abruptly to the position of capacity long.

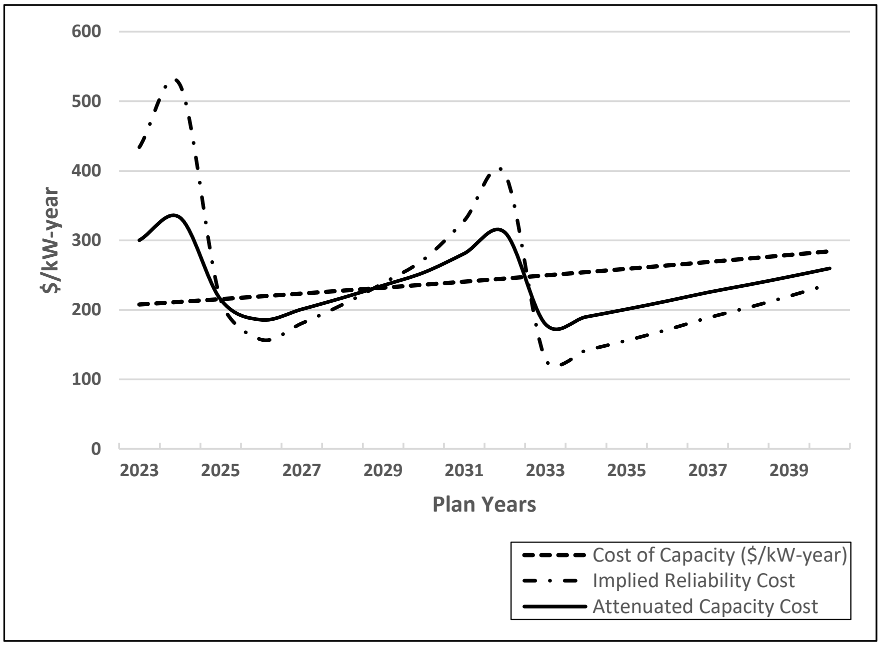
Furthermore, generation capacity expansion plans can vary substantially from one year to the next as facility choices and build schedules change. System conditions, including the long-term outlook for system loads, estimates of capacity cost options,[12] and the availability of heritage generation, change frequently. In short, expansion plans are somewhat fluid from one year to the next. Generally speaking, the attenuation approach for determining the annual marginal generation capacity cost over years may better adhere to central tendency and prove to be more useful for assessing CDM plans and tariff options.

Presented below are Hydro's projections of generation capacity costs for years 2023-2040, based on internal capacity costs, system reliability, and attenuation methods.

[11] Large differences in system reliability across years, both observed and estimated, are common to both major electric utilities operating within highly meshed regional networks, and smaller, rather isolated systems. In the case of smaller power systems, capital indivisibility contributes to the variation in system reliability: capacity additions are likely to provide greater capacity than needed to satisfy reliability standards at the time of installation. Similarly, random generator unit outages can represent an abrupt loss of a significant share of total capacity during critical peak load conditions.

[12] Contemporary generation expansion plans may take account of numerous supply-side options involving, over future plan years, widely varying cost estimates, where all-in installed costs are highly specific to potential sites.

Projections of Generation Costs Under Alternative Methods:
Internal Capacity Cost, System Reliability, Attenuation ($/kW-year)



As shown, the attenuation algorithm tends to significantly mitigate the large variation in system reliability, particularly during the time of installation of capacity additions.[13] The net results are twofold: generation capacity costs do exhibit large variation over plan years. Second, the general path of generation costs under attenuation follows Hydro's estimates of capacity costs.[14]

[13] Attenuation algorithms can assume several variations including, potentially, exponential smoothing methods. The specific method used herein is a practical though ad hoc methodology that draws on both annual capacity costs and estimates of LOLH for selected analysis years. The current approach requires the specification of parameters. As Hydro's expansion plans evolve through time, parameterization will undoubtedly be updated in order to reflect the contemporary outlook: projections of peak loads, estimates of system reliability, and capacity cost options.

[14] The discounted sum of annual costs ($/kW-year) for 2023-2040 under the *internal capacity costs*, *implied reliability*, and *attenuation algorithm* approaches are equal to $4,595, $4,421, and $4,350 respectively.