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February 26, 2016

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Marginal Cost Study – Part II

Further to our correspondence of February 19, 2016, please find attached the original and 12 copies of the above referenced report.

We trust this to be satisfactory. However, should you have any questions, please feel free to contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/bds

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Thomas Johnson – Consumer Advocate
Thomas J. O'Reilly, Q.C. – Cox & Palmer

MARGINAL COST REPORT, PART II

ESTIMATION: MARGINAL COSTS OF GENERATION AND TRANSMISSION SERVICES for 2019

prepared for:

NEWFOUNDLAND LABRADOR HYDRO

developed by:

David Armstrong

Robert Camfield

Will Jones

Mathew Morey

CHRISTENSEN ASSOCIATES ENERGY CONSULTING

800 University Bay Drive, Suite 400

Madison, Wisconsin 53705

February 26, 2019

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February 25, 2019

[1] Principal investigator and primary author.

1.0 INTRODUCTION

This Part II Report presents estimates of the marginal costs of generation and transmission services (G&T services) provided by Newfoundland and Labrador Hydro ("NLH" or "Company"), for forward year 2019. Part II carries out the marginal cost methods identified in Section 3.0 of the Part I Report[2], *Summary of Methods*. As identified in the Part I Report, NLH's estimates of marginal costs of G&T services provide guidance for:

- the allocation of financial costs (revenue requirements) to industrial customers and power distributors (Newfoundland Power); and,
- the design of tariffs providing G&T service to Island and Labrador customers of NLH, where the end result satisfies fairness criteria while simultaneously providing consumers with price incentives to use electricity most efficiently.

Marginal cost refers to the change in cost with respect to a change in the level of electricity services provided. For NLH, G&T services are provided at numerous points of delivery across NLH's lower voltage transmission system, referred to as the 66kV-138kV network. Marginal costs include energy and reliability cost elements, where reliability refers to the costs incurred by consumers as a consequence of the loss of power supply, referred to as *consumer outage costs*.

Marginal costs can be estimated for G&T services in combination, or separately for generation and for transmission. The 2019 estimates of marginal costs reported herein follow the latter approach: marginal costs are estimated and reported separately for generation and transmission services, then combined to obtain estimates of the *All-In Marginal Costs* including, for generation, marginal costs of energy, operating reserves, and capacity and, for transmission, marginal costs of energy (line losses) and capacity. Cost elements for NLH's generation and transmission functions involve short- and long-run cost elements, and are estimated as follows:

1.1 GENERATION SERVICES

<u>Energy Cost based on Opportunity Costs</u>: Marginal energy costs set according to projections of marginal energy prices for regional markets including the New York ISO and ISO New England.

<u>Reliability Cost measured according to 1) Internal Capacity Costs or 2) Opportunity Costs</u>:

- *Internal Capacity Costs* refers to the incremental costs of oil-fired combustion turbine generators, situated on a greenfield site near NLH load centers. (Model 1)
- *Capacity Auction Prices (Opportunity Cost)*, as determined by the capacity markets of the Northeast wholesale markets.[3] (Model 2)

[2] "Marginal Cost Report, Part I, Methodology: Estimation of Marginal Costs of Generation and Transmission Services for 2019", dated December 29, 2015 and filed with the Public Utilities Board December 30, 2015.

[3] Operating reserve prices are included within the reported marginal energy costs, under the Opportunity Cost approach (Model 2).

For purposes of reporting herein, the *Opportunity Cost* of generation capacity (Auction Prices) is the primary, though not exclusive, measure of all-in marginal costs estimates. We anticipate that, for the applications identified above (cost allocation, tariff design), NLH will generally utilize all-in marginal costs inclusive of the New England ISO (NE ISO) auction price of generation capacity for 2019.

1.2 TRANSMISSION SERVICES

Energy Costs (Losses) Estimated through Simulation Studies: Marginal line losses for transmission services are determined from a set of transmission load flow simulation studies. These transmission studies reflect the expected loads of the Island and Labrador service regions, as well as the configuration of the NLH transmission system for 2019

Reliability Costs Based on Capacity Costs: Estimates of marginal reliability costs of transmission will be determined from the Company's peak-load related expenditures (capacity) for transmission, as planned for forward years through 2023.

As described, estimates of the 2019 NLH marginal costs utilize a combination of short- and long-run marginal cost concepts. The 2019 marginal costs are estimated in hourly frequency. For purposes of reporting, the results are presented in monthly frequency, and for peak and off-peak timeframes.

2.0 ESTIMATES OF 2019 MARGINAL COSTS[4]

GENERATION: Marginal Cost of Energy and Reserves: Marginal cost of generation including energy and operating reserves are based on the opportunity costs, determined through the competitive power auctions organized by Northeast U.S. regional transmission organizations, the New York ISO and the New England ISO. These market auction procedures take account of the demand for and supply of generation resource, resulting in market prices for energy and reserves. Market prices capture the market worth of power generation insofar as, by definition, competitive auction-based market prices are equivalent to marginal cost for wholesale electricity markets as a whole. Within unbundled markets, energy and reserve prices are estimated in hourly frequency for same-day (real time) and day-ahead timeframes. Although not reported separately, the marginal costs of operating reserves cover, in total, regulation, spin, and non-spin operating reserves; reserve prices are scaled to 4.5% of the reserve prices paid to generators, in order to reflect the net price paid by loads.[5]

As identified above, *Marginal Cost of Reliability* can be based on estimates of the internal costs of capacity incurred by NLH to provide reliability (Model 1), or according to opportunity costs – capacity auction prices (Model 2). As discussed in the Part I Report, under plausible long-term planning

[4] The marginal costs reported herein are non-weighted averages of the estimates of hourly marginal cost.

[5] The cost of reserves is small, averaging $0.70/MWh, stated in Canadian dollars. Arguably, reserve prices should not be incorporated within marginal costs under the internal capacity cost approach, insofar as they are implicit within the marginal costs of generating capacity.

assumptions, capacity costs approximate the shadow prices of consumer outage costs – the true value of reliability.

TRANSMISSION: Marginal Energy Cost is in the form of line and transformer loss percentages as determined through power system simulation tools (load flow analysis). *Marginal Transmission Reliability Costs*, like generation, are in the form of capacity cost proxies.

ALL HOURS: Presented below are 2019 estimates of marginal generation and transmission costs for Newfoundland-Labrador Hydro.

Table 1: Estimates of Marginal Generation and Transmission Costs for NLH, by Month for 2019 (CAD/MWh)

Average Hourly Marginal Costs (CAD/MWh)

		Energy and Reserve Costs		**Capacity Costs**		**All-In Marginal Costs including Energy, Capacity, Reserves, Losses**	
All Hours		NE ISO	NY, Zone A	Gen	Trans	NE ISO	NY, Zone A
Month	Jan	49.27	51.45	10.00	10.39	67.94	70.14
	Feb	45.04	45.55	8.71	15.19	67.42	67.94
	Mar	33.06	38.63	5.26	16.23	53.63	59.21
	Apr	32.76	32.62	2.04	7.66	42.11	41.97
	May	35.88	33.50	3.48	0.00	38.87	36.49
	Jun	37.34	38.00	9.97	0.00	45.96	46.63
	Jul	44.67	47.91	22.83	0.00	64.39	67.67
	Aug	41.33	45.01	11.13	0.00	50.98	54.68
	Sep	34.24	34.98	6.19	0.00	39.59	40.33
	Oct	37.54	38.12	3.26	0.00	40.32	40.90
	Nov	40.31	41.04	5.29	0.20	44.98	45.72
	Dec	44.51	49.27	10.14	4.51	57.55	62.33
	Annual	39.66	41.36	8.21	4.45	51.10	52.81

The marginal energy and reserve costs for Northeastern wholesale electricity markets (NE ISO; NY ISO, Zone A) reflect estimates of market prices available to NLH from the sale of energy (and reserves) into the respective market. These 2019 marginal cost estimates (opportunity cost-based prices) are non-weighted, adjusted for the estimated Canadian-US exchange rate (1.212), and incorporate charges for transmission line losses along the two regional "paths to markets" available to NLH through Nova Scotia/New Brunswick and through Hydro Quebec, respectively. Also, transmission access fees are incorporated in the marginal cost estimates derived from the markets of the NE ISO.

Several noteworthy observations can be drawn from Table 1, as follows:

- Average monthly prices for energy are only modestly higher during the summer months of July and August, than for the average across the year. This pattern follows directly from load patterns. Over the most recent four years (2012-2015), electricity consumption across months demonstrates that summer peak loads are only modestly higher than winter peak loads, within Northeast electricity markets.

- Inclusion of generation capacity costs (determined under the opportunity cost method – i.e., auction price-basis – within marginal costs causes July marginal costs to rise significantly above the annual average. This result is not surprising: the demand for generating capacity rises non-linearly, as peak loads over the calendar year – i.e., the summer peak loads of July stated on expected value basis – are approached.
- Because the loads and prices of Northeast markets are comparatively high in summer, NLH is in a favorable position for the profitable sale of power during summer months. This is a direct result of the countervailing electricity consumption patterns for Newfoundland and Labrador, where energy consumption is sharply concentrated during winter months.

PEAK HOURS: Shown below are marginal costs for the widely-followed commercial peak period of wholesale electricity markets, week-day hours ending 7am–10pm, as established by the North American Energy Standards Board (NAESB).

Table 2: Estimates of Peak Period Marginal Generation and Transmission Costs for NLH, by Month for 2019 ($CAD/MWh)

Average Hourly Marginal Costs (CAD/MWh)

		Energy and Reserve Costs		**Capacity Costs**		**All-In Marginal Costs including Energy, Capacity, Reserves, Losses**	
Peak Hours		NE ISO	NY, Zone A	Gen	Trans	NE ISO	NY, Zone A
Month	Jan	53.88	59.18	12.53	17.74	81.94	87.26
	Feb	50.75	51.50	10.49	23.57	82.94	83.71
	Mar	37.61	42.02	6.86	16.35	59.62	64.04
	Apr	36.48	34.49	2.50	13.98	52.52	50.54
	May	39.86	35.53	4.77	0.00	43.94	39.62
	Jun	44.44	42.80	10.62	0.00	53.48	51.86
	Jul	58.88	59.43	24.61	0.00	79.82	80.40
	Aug	50.51	53.47	13.65	0.00	62.17	65.15
	Sep	38.09	35.82	8.06	0.00	44.96	42.71
	Oct	43.31	41.73	4.20	0.00	46.87	45.29
	Nov	45.25	45.08	6.61	0.40	51.22	51.07
	Dec	50.63	54.01	11.88	9.47	69.95	73.35
	Annual	45.89	46.34	9.78	6.69	60.81	61.28

The analysis results presented above for the peak period largely conform to the *all hours* marginal cost patterns shown in Table 1: opportunity cost-based marginal costs are comparatively high during summer peak load timeframes. The week-day peak period constitutes a 48% share of the total hours of a typical month but a larger share of total energy – thus, higher average loads. As a consequence, capacity costs on the margin are concentrating during peak period hours, leading to higher all-in marginal costs, for summer months in particular. This is evidenced above: for NE ISO and NY ISO respectively, annual marginal energy costs per MWh rise from $39.66 and $41.36 to $45.89 and $46.346 per MWh during peak hours – an increase of 13.9% across the two Northeast markets. In contrast, all-in marginal cost for the NE ISO and NY ISO – which includes energy and capacity – rise from an average annual level of $51.10 and $52.81 per MWh to $60.81 and $61.28 for peak period hours, an increase of 17.5% – a difference of about 26%.[6] In short, capacity costs are strongly centered during peak load hours. Generation capacity cost – for (and only for) the auction-price basis of generation capacity cost – fall almost exclusively during the summer months of June through early September; transmission capacity costs are concentrated during the winter months of January through March and to a lesser extent, April.

OFF-PEAK HOURS: Below are shown 2019 marginal costs for the commercial off-peak hours, including hours ending 11pm–6am for week days and the 24 hours of each of the two weekend days, for a total of 88 hours of the 168 hours that comprise a week.[7]

Table 3: Estimates of Off-Peak Period Marginal Generation and Transmission Costs for NLH, by Month for 2019 (CAD/MWh)

Average Hourly Marginal Costs (CAD/MWh)

		Energy and Reserve Costs		**Capacity Costs**		**All-In Marginal Costs including Energy, Capacity, Reserves, Losses**	
Off-Peak Hours		NE ISO	NY, Zone A	Gen	Trans	NE ISO	NY, Zone A
Month	Jan	44.75	43.88	7.53	3.19	54.24	53.38
	Feb	39.85	40.14	7.08	7.57	53.30	53.60
	Mar	29.31	35.83	3.95	16.13	48.70	55.23
	Apr	29.20	30.83	1.60	1.61	32.16	33.78
	May	31.99	31.51	2.21	0.00	33.91	33.43
	Jun	31.66	34.16	9.44	0.00	39.94	42.45
	Jul	30.76	36.63	21.09	0.00	49.30	55.21
	Aug	33.10	37.43	8.87	0.00	40.93	45.27
	Sep	30.88	34.24	4.55	0.00	34.89	38.25
	Oct	31.89	34.60	2.34	0.00	33.91	36.61
	Nov	35.99	37.50	4.13	0.02	39.52	41.04
	Dec	39.01	45.01	8.59	0.05	46.42	52.43
	Annual	33.98	36.81	6.79	2.41	42.25	45.10

The typical level of off-peak marginal costs for comparable months are lower than the annual average marginal cost, by definition; the substantive questions are matters of magnitude and differences in relative cost patterns over months. For both the energy and reserves, and the all-in marginal cost metrics, the percentage differences are similar. Two observations are as follows:

- For the all-in marginal cost metric, the absolute percent difference in off-peak marginal costs compared to the average, is somewhat less than the percentage difference between peak period marginal costs and the average.
- The lower percentage difference between off-peak and average marginal costs, compared to the difference between on-peak and average marginal costs, also holds true for marginal energy and operating reserves. This is also not surprising, as marginal operating costs rise non-linearly as loads rise.

[6] That is, 17.53% is 26.1% above 13.9%.

[7] It is useful to note that, for months, the total of peak hours and off-peak hours are specific to the calendar year insofar as the share of week days and weekend days within each month can vary from one year to another.

For the all-in measure of marginal cost, the differences are largely attributable to the presence of capacity costs, for both generation and transmission in peak period hours, as shown above. This is most evident in the averages across months. For the annual period,[8] the average cost of capacity is $8.21/MWh and $4.45/MWh for generation and transmission, respectively. Within peak period hours, capacity costs rise to $9.780/MWh and $6.69/MWh, for generation and transmission respectively. Owing predominantly to variation in daily load patterns, comparatively small shares of G&T marginal capacity costs frequent off-peak periods. Thus, while at substantially lower cost levels, capacity costs are nonetheless also present during off-peak hours: $6.79/MWh and $2.41/MWh for generation and transmission respectively.

3.0 VARIATION IN 2019 MARGINAL COST PATTERNS

Within months, hourly and average daily marginal energy prices vary considerably as a consequence of variation in loads and, on occasion, abrupt loss in available supply in the form of unexpected forced outages of generator units and, for transmission, in the form of occasional loss of critical-path transmission circuits. Variation can be expressed with commonly applied metrics of statistical distribution. Below are shown two measures of variation: the standard deviation of hourly estimates of marginal costs and, second, the differences between the maximum and average marginal energy costs, shown graphically. Each measure of distribution is presented for peak and off-peak time frames, by month. The first measure of variation, standard deviation, is as follows for peak and off-peak periods across months:

Table 4: Variation in Hourly Marginal Costs during Peak Period Hours for NLH, by Month for 2019 (CAD/MWh)

Hourly Standard Deviations of Marginal Costs (CAD/MWh)

		Energy and Reserve Costs		Capacity Costs		All-In Marginal Costs including Energy, Capacity, Reserves, Losses	
Peak Hours		NE ISO	NY, Zone A	Gen	Trans	NE ISO	NY, Zone A
Month	Jan	7.85	10.00	11.75	15.65	19.40	20.43
	Feb	8.57	8.53	1.07	15.21	18.95	19.23
	Mar	3.83	2.03	0.00	16.88	17.49	17.30
	Apr	2.84	1.27	0.00	13.25	13.25	13.08
	May	3.18	1.56	21.36	0.00	19.04	18.51
	Jun	5.85	5.63	61.11	0.00	51.75	51.53
	Jul	15.10	13.60	123.29	0.00	103.54	103.14
	Aug	8.86	9.38	32.28	0.00	26.93	26.57
	Sep	5.11	4.17	43.32	0.00	37.29	37.20
	Oct	5.01	3.27	0.00	0.00	5.01	3.27
	Nov	6.13	4.06	0.00	2.17	6.74	4.65
	Dec	8.02	7.02	13.60	14.27	20.51	19.41
	Annual	10.18	11.20	49.80	12.86	45.39	45.80

[8] To reaffirm, all analyses are conducted in hourly frequency.

As shown in Table 4 above, standard deviations across the average hourly marginal energy and reserve prices follow relative load levels across months. The relationship is strongly non-linear, as evidenced by the differences between the variation for the off-peak months of April and May and variation during peak load months of July and August.

Table 5: Electricity Consumption across Months for the New England ISO during 2012-2013 (GWh)

New England ISO: Monthly Energy Across Months	2012	2013
Jan	11,322	11,639
Feb	10,151	10,349
Mar	10,188	10,664
Apr	9,425	9,461
May	10,164	9,940
Jun	10,822	11,022
Jul	13,052	13,840
Aug	12,982	11,734
Sep	10,307	10,256
Oct	9,849	10,003
Nov	10,213	10,295
Dec	11,101	11,701
Total	129,576	130,903

When assessed with respect to variation in energy consumption across months, presented above, the sensitivity of variation in marginal energy costs and prices to loads becomes starkly evident. Energy consumption increases by approximately 32% between the off-peak months of April and May and the peak load months of July and August, for Northeast U.S. markets. For these two timeframes, statistical variation – i.e., the standard deviation of the distribution of hourly marginal cost of energy and reserves – increases by approximately fourfold for the NE ISO and eight times for the NY ISO. Note that the relative increases in variation within hourly all-in marginal costs (including G&T capacity costs), between May-June and July-August, rise by a similar magnitude (though somewhat less).

As presented below, a similar pattern of variation is found for off-peak timeframes though, as expected, the differences in hourly variation in marginal energy and reserve prices are remarkably less, generally speaking.

(reference following page)

Table 6: Variation in Hourly Marginal Costs during Off-Peak Period Hours for NLH, by Month for 2019 (CAD/MWh)

Hourly Standard Deviations of Marginal Costs (CAD/MWh)

		Energy and Reserve Costs		**Capacity Costs**		**All-In Marginal Costs including Energy, Capacity, Reserves, Losses**	
Off-Peak Hours		NE ISO	NY, Zone A	Gen	Trans	NE ISO	NY, Zone A
Month	Jan	5.31	5.41	7.19	7.29	12.72	12.23
	Feb	4.99	3.29	6.07	11.89	16.03	14.94
	Mar	2.02	3.82	4.67	17.24	18.35	19.36
	Apr	2.80	1.88	2.55	5.15	6.12	5.81
	May	2.92	2.84	4.67	0.00	4.67	4.52
	Jun	4.15	3.95	10.29	0.00	9.54	9.07
	Jul	5.41	4.93	14.60	0.00	12.89	12.40
	Aug	5.20	4.41	8.25	0.00	7.62	6.91
	Sep	3.68	3.28	7.01	0.00	6.79	6.21
	Oct	3.37	2.57	3.02	0.00	4.12	3.63
	Nov	5.31	4.36	4.87	0.35	6.57	5.62
	Dec	9.73	9.78	7.14	0.63	11.35	11.25
	Annual	6.78	6.26	8.96	8.16	13.03	13.23

As observed, the standard deviation in the hourly energy and reserve prices between warm summer (July, August) and April and May increases by 86% and 98% for the NE ISO and NY ISO, respectively – a comparatively modest differential. However, in contrast with marginal costs within peak load hours, the differences in the variation in all-in marginal costs, for off-peak months of April and May compared to the peak load months of July and August, is higher: for off-peak hours, statistical variation rises by approximately 50% during July and August, a direct consequence of the presence of sizable levels of marginal generation capacity costs within selected off-peak hours during July.[9]

The charts below present the differences between average and marginal energy prices, as estimated for 2019.

(reference following page)

[9] The comparatively high variation in the December off-peak energy and reserves costs is significantly impacted by an anomalous, high reserve price during one hour.

Chart 1: Average and Maximum Marginal Energy Price Estimates during Peak Hours New England ISO and New York ISO Zone A for 2019, USD/MWh

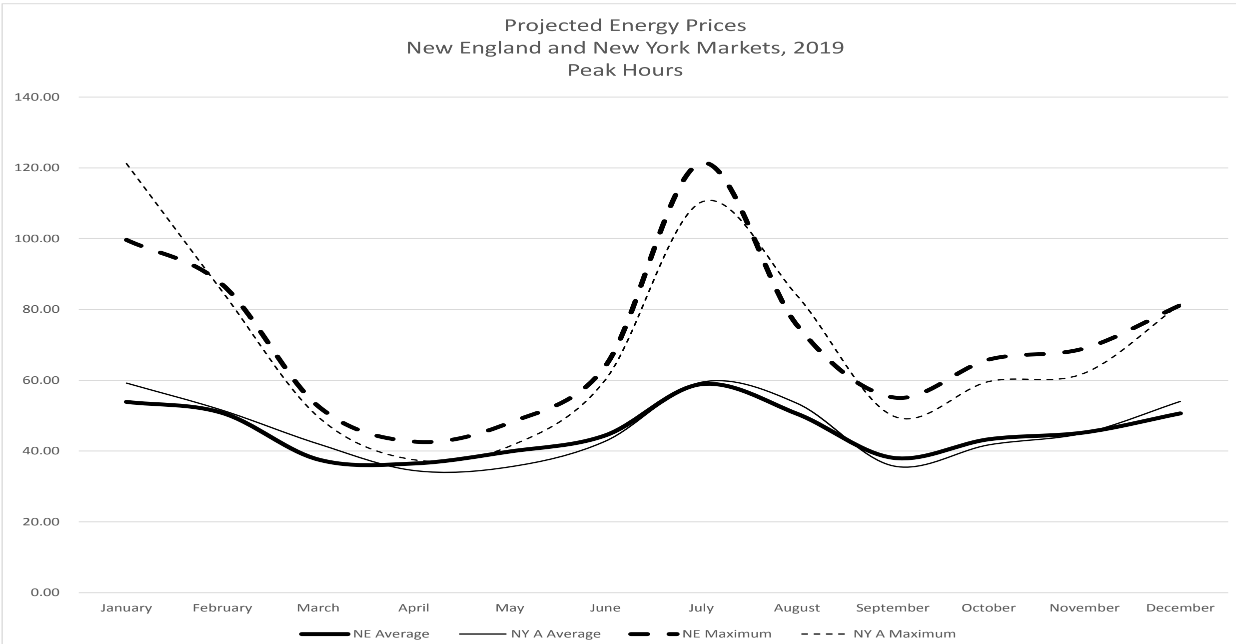
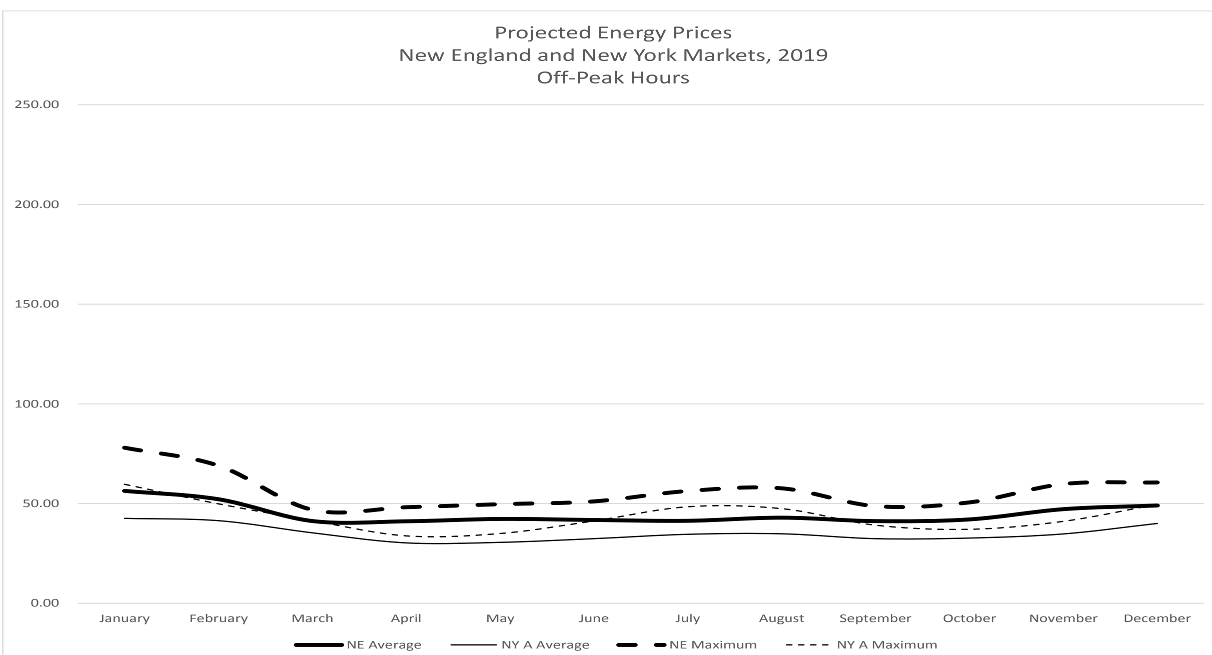


Chart 2: Average and Maximum Marginal Energy Price Estimates during Off-Peak Hours, New England ISO and New York ISO Zone A for 2019, USD/MWh



The marginal energy cost patterns revealed above are common to electricity markets, and are driven by a key feature of electricity markets – non-storability[10] on a meaningful scale. As a consequence, the demand for, and supply of, electricity must be balanced exactly in high levels of frequency (i.e., five minute intervals). Because of non-storage, electricity cannot be readily arbitraged – produced during low-cost hours when supply is plentiful, stored, and then provided during high-value timeframes. The above charts reinforce the evidence presented in the above tables: marginal costs – and, similarly, competitive market clearing prices – often vary greatly from one day to another. As demands approach total supply, non-restricted market prices can approximate consumer outage costs, reaching well beyond $2,000/MWh.

As shown in Chart 1 (Peak Period Hours), for marginal energy prices in both NE ISO and NY ISO markets, the differences between the estimates of the hourly maximum and the average monthly prices expand by factors nearing 4 to 1 between off-peak seasons and the summer peak month, July. Add to this capacity costs, and the differences between average and maximum level prices narrow, because of the fourfold increases the maximum-average differences for the off-peak season, while the July maximum-average difference declines somewhat.

Off-peak prices (marginal energy costs) revealed in Chart 2 are strongly juxtaposed to the peak period energy prices presented in Chart 1. For January, comparatively modest differences are observed between the maximum and the average monthly prices: January maximum-average differences appear to be 3-5 times greater than the maximum-average price differences for the off-peak seasons (April, May). Further, the inclusion of capacity costs causes the marginal costs differences between peak and off-peak timeframes to decline somewhat, a result largely attributable the seasonal energy differences and the frequency with which loads approach capacity constraints across months.

In summary, day-to-day and monthly variation in estimates of marginal costs generally increase with the inclusion of capacity costs – as expected. The differences are comparatively large and, for this reason, it is appropriate for NLH to explore the development of tariff options based on dynamic pricing, where the marginal prices facing consumers are based on short-run marginal costs, set accordingly to market-based opportunity costs. Such approach, when hedged under the structure of a two-part tariff – i.e., a forward-spot combination – provides the means to significantly improve market efficiency: increased reliability while simultaneously lowering the overall level of prices to ultimate consumers.

4.0 GENERAL STRUCTURE OF NLH MARGINAL COSTS

The hourly estimates of the 2019 marginal costs for NLH are based on the second of two potential model structures, as follows.

[10] Notwithstanding the energy storage capability of pondage and pumped-storage hydraulic facilities.

4.1 Model 1: Market-Based Energy Costs and Internal Generation Capacity Costs

The marginal costs under the Model 1[11] construct are defined as follows:

$$All\ In\ Marginal\ Cost\ = MEC * LL^{Network} + GenCap^{Internal\ Cost} * LL^{Peak} + TransCap$$

where,

$$MEC = marginal\ energy\ cost\ (competitive\ market\ prices)$$
$$GenCap^{Internal\ Cost} = generation\ capacity\ costs\ of\ NLH$$
$$TransCap = transmission\ capacity\ costs$$
$$LL^{Network} = marginal\ loss\ factors, NLH\ network\ and\ transmission\ paths\ to\ wholesale\ markets$$
$$LL^{Peak} = marginal\ losses\ at\ peak\ loads$$

4.2 Model 2: Market-Based Energy and Opportunity Costs of Generation Capacity

The definition of marginal costs under Model 2 is as follows:

$$All\ In\ Marginal\ Cost\ = (ME\_RC + GenCap^{Market}) * LL^{Network\ and\ Path} + TransCap$$

where,

$$ME\_RC = marginal\ energy\ and\ operating\ reserve\ costs\ (competitive\ market\ price)$$
$$GenCap^{Market} = generation\ capacity\ auction\ prices\ of\ competitive\ markets$$
$$TransCap = transmission\ capacity\ costs$$
$$LL^{Network\ and\ Path} = marginal\ loss\ factors, NLH\ network\ and\ transmission\ paths\ to\ wholesale\ markets$$ [12]

Hourly generation and transmission costs are stated as $/kW-year and, as discussed in the Part I Report, can be assigned to hours in several ways, including estimates of the statistical distribution of *loss of load hours* (LOLH) or *expected unserved energy* (EUE) among hours. The immediate study, however, assigns annual generation and transmission capacity costs ($/kW-year) to hours using two alternatives, as follows:

> *Parameterized Max Function*, which distributes annual capacity costs *pro rata* to the highest hourly loads, as selected by the function. Selection can be fairly narrow or broad, depending on the model parameters.
>
> *Statistical Distribution of Peak Demands*, where the historical frequency of peak load occurrences within months and hours serve as the basis to distribute annual costs to hours.

[11] Reference Appendix A for a more complete specification of marginal costs under Models 1 and 2.

[12] Note that, in the case of the Opportunity Cost framework under export conditions, line losses are negative, thus reducing the value of internal resources. However, line losses reverse under the import case, thus raising the marginal value of resources. For NLH, only under rare circumstances does the import case hold.

While both methods are highly plausible, we are attracted to the parameterized max function approach, because of flexibility. In addition, it is common to find that the limits of the available supply of capacity is approached much more broadly across hours than is often suggested by planning models. It is nonetheless useful to draw upon the analytics reached through generation planning tools to determine the appropriate parameters for use within the Max Function, as applied.

5.0 COST ESTIMATES, GENERATION AND TRANSMISSION COMPONENTS

As identified above, the 2019 estimates of marginal costs include energy and capacity components for each function, generation and transmission. Estimates of the various cost components are presented in the following discussions.

5.1 MARGINAL GENERATION COSTS

Marginal energy costs are measured as opportunity costs, and set equal to estimates of market prices for energy and reserves, as determined by regional wholesale electric markets including the NE ISO and the NY ISO. Marginal generation capacity costs reflect two methods: the all-in bus bar costs of the Company's planned capacity additions (marginal cost Model 1); estimates of capacity auction prices, opportunity costs (marginal cost Model 2).[13] Marginal energy costs and capacity costs are reviewed separately below.

5.1.1 Marginal Energy Costs, Generation

As mentioned above, estimates of marginal energy costs assume an opportunity cost basis, where hourly energy costs ($/MWh) are based on the 2019 electricity market outlook of Nalcor Energy for the two U.S. wholesale electricity market regions in which Nalcor Energy will market hydro power, including the markets operated by the New York ISO and ISO New England. As a matter of structure, these two regional energy markets are highly similar: bid-based simultaneous auctions to determine real-time and day-ahead generation prices (spot, forward) for energy and operating reserves.

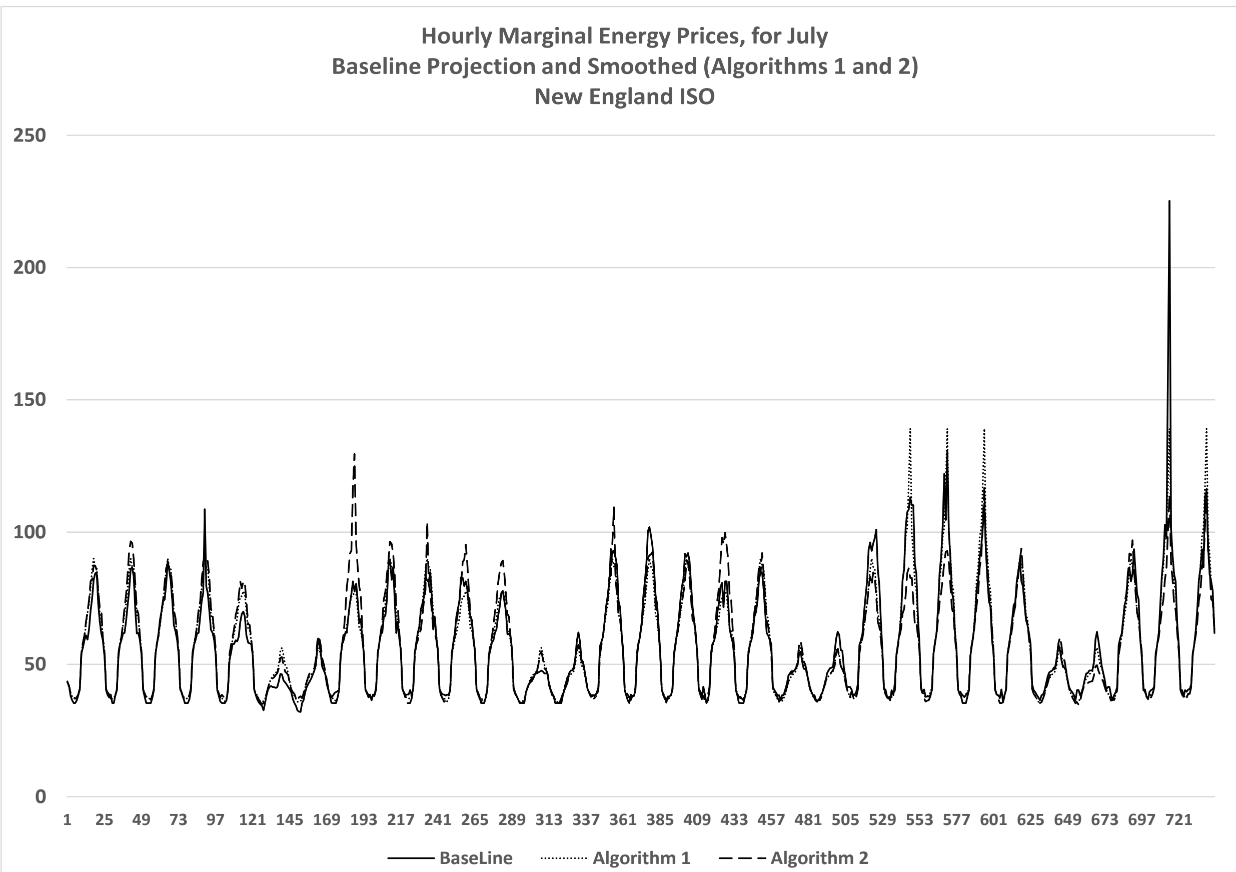
Projections of energy prices across these two markets can be determined through market simulation: for each region, projections of electricity demand are aligned with electricity supply (i.e., generation dispatch curve), as simulated. For each region, projections of marginal energy cost take account of plans for, and forecasts of, new generators, projections of fuel prices, and various generator unit parameters including heat rates and unit availability (EFOR). Analysis procedures take account of expected maintenance time, where individual units are scheduled for maintenance within the year according to the principle of least cost impact. Once generator maintenance is scheduled, the algorithm then commits units on the basis of startup costs and current operating status. Following commitment, each model iteration obtains a different availability (forced outage realization) for each of the various generator units, leading to different sets of generators and reserve levels across hours. The set of

[13] As mentioned, the marginal costs of generating capacity, incorporated within the estimates of all-in marginal costs, are based on opportunity costs (Model 2).

available generators is then ordered into a supply function according to running costs (fuel and variable operations and maintenance expenses). Marginal energy cost – measured at the reference bus plus marginal line losses and congestion for the relevant market zone/area – is equal to the intersection of the estimated level of demand and the supply function.[14] For the immediate study, marginal reserve prices (regulation, spin, and non-spin reserves) are drawn from observed hourly prices over several years, and then scaled to the demand side of wholesale electricity markets.[15]

As mentioned, marginal energy costs can vary greatly within short-run timeframes. Day-to-day variation within estimates of hourly prices for the New England ISO are shown below.

Chart 3: Estimates of Hourly Marginal Energy Costs, New England ISO, for July 2019 (USD/MWh)



[14] Note that the simulation of wholesale market prices of generation is similar to the simulation of internal production costs.

[15] The scaling parameter, set equal to 4.5%, can be revisited and potentially reset. Generally speaking, system operators will vary the physical quantities of reserves held, depending on system conditions. Reference *OP-8 – Operating Reserve and Regulation*, within the operating procedures of ISO New England.

Restated in brief, the statistical variation in hourly and daily marginal energy costs (and reliability costs also) can be exploited with the appropriate tariff mechanisms – e.g., short-run marginal cost-based dynamic pricing – where the end result is substantial gains in the form of reduced costs and improved reliability for ultimate consumers.

5.1.2 Marginal Generation Reliability Costs

5.1.2.1 Marginal Capacity Costs Internal to NLH (Model1)

For Model 1, NLH reliability costs for the generation function are based on the costs of the combustion turbine (CT) supply technology. CTs are well recognized as the least-cost basis by which electricity service providers satisfy generation reliability, and estimates of CT capacity costs, sometimes referred to as the *cost of new entry*, are commonly used as the basis to determine marginal reliability costs for generation services. This standard approach is not without reason: high flexibility, capable of high ramp rates, short construction times, and modest-sized footprint. In addition, combustion turbine generating units are available in a wide range of capacity sizes. Driven in part by the increased availability and a lower expected path of petroleum and natural gas fuel prices, CTs have represented a sizable share of the total capacity additions in North American over recent years.

Stated on a $/kW-year basis, CT capacity costs vary considerably, owing largely to differences in the specifications of units, site-specific factors, and scale economies favoring larger units. For this reason, capacity cost estimates are drawn from NLH's planned expenditures for incremental CT capacity. The cost estimate of NLH's oil-fueled CT capacity, planning-based proxy units, serve as the foundation for the estimation of internal marginal generation capacity cost, and is specified as follows:

$$Capacity\ Cost_{CT} = \left(I_{CT} + I_{M\&S} + I_{F\_Inv} + WK\right) * ECC + I_{GP} * ECC_{GP} + OM_{CT} + A\&G_{wrt\ OM} + Ins_{K,Ops}$$

where,

$Capacity\ Cost_{CT} = total\ annual\ direct\ and\ indirect\ cost\ of\ CT\ technology$

$I_{CT} = direct\ CT\ investment\ expenditure\ including\ interest\ during\ construction$

$I_{GP} = investment\ expenditure\ in\ indirect\ plant\ and\ equipment$

$I_{M\&S} = investment\ expenditure\ for\ materials\ and\ supplies\ inventory$

$I_{F_{Inv}} = investment\ expenditure\ in\ fuel\ inventory$

$WK = working\ capital\ associated\ with\ fixed\ O\&M\ and\ fuel\ inventory$

$ECC = economic\ carrying\ charge\ rate, generation(CT\ expected\ capital\ life)$

$ECC_{GP} = economic\ carrying\ charge\ rate, general\ plant$

$OM_{CT} = annual\ expenditure\ for\ operations\ and\ maintenance$

$A\&G_{wrt\ OM} = annual\ expenditure\ for\ administrative\ and\ general\ expenses$

$Ins_{K,Ops} = annual\ expenditure\ for\ insurance, plant\ and\ operations$

As presented above, generation capacity costs, in total, include the carrying charges on capital and operating costs, stated annually. Capital-related cost is equal to the sum of the direct investment expenditures, general plant, fuel inventory, materials and supplies (M&S), and working capital, multiplied by the carrying charge rate. The carrying charges are based on the *economic carrying charge* approach (ECC),[16] sometimes referred to as trended real capital costs.[17] ECC-based charges rise with respect to shorter capital life; as presented below, the ECC rate for general plant is substantially higher than the ECC rates for generation or transmission capacity– the cost of which is discussed subsequently.

As mentioned, direct investment expenditures are based on NLH's planned for costs associated with the installation of two 25MW CTs at a greenfield site situated on the Avalon Peninsula. These costs, stated in 2015 Canadian dollars, are escalated to 2018-2019 dollars based upon expected inflation, where the historical relationship between gas-fueled generation, simple and combined cycle generators, and observed inflation is accounted for. Further, the capacity cost estimates presume that NLH's CT generators are constructed over a two-year construction cycle, with 27.8% of expenditures occurring during the first year and the remaining share of the total expenditures (72.2%) taking place during the subsequent year. Interest is capitalized during construction at a 7.0% weighted average cost of capital.

Investment in general plant is drawn from the historical relationship, for years 2008-2014, between NLH's capital investment in general and common plant and investment in generation and transmission facilities, measured in real terms, net of economic depletion (depreciation). The materials and supplies inventory associated with NLH's CTs is based on the level of materials and supplies associated with gas-fueled generation, for a sample of several modest-sized U.S. electricity utilities during 2013.[18]

Fuel inventory is set at a sufficient level to cover NLH's expectations for continuous or near-continuous running hours for the planned CT over one week (168 hours), an expected heat rate of 9430/kWh, and energy content of 5.8 MMBTU per barrel. The CTs will utilize No. 2 fuel oil. Prices for No. 2 oil are for

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[16] Economic Carrying Charge refers to the annual "all-in" carrying charges on capital including depreciation, payback of principal, interest charges, corporate income taxes where appropriate, and return on capital including investor perceptions of risk. The ECC rate can be calculated as:

$$I\,\{[(k-i+t)(1+i-t)^n] \,/\, (1+k)\}\{(1+k)^m \,/\, [(1+k)^m + (1+i-t)^m]\}$$

where *I=investment*, *k=capital charge rate*, *i=expected inflation*, *t=technological advance*, *n=year*, and *m=expected life of capital*. CA Energy Consulting has this approach automated within a computer program for expedient calculation of the ECC rate.

[17] The economic carrying charge method, for the determination of capital charges, reflects the expected escalation in the costs of new investment over time. Under the condition of rising prices for capital, the economic carrying charges rise over the life of the capital. Thus, the ECC path for capital charges over the life of assets is in sharp contrast to declining capital charges over time, under conventional original cost accounting. Importantly, the discounted value of economic carrying charge over time equal that of the charges under original cost accounting. Under the condition of no escalation in prices over time, the ECC approach is equivalent to levelized fixed charges over the life of capital.

[18] M&S is determined as the ratio of M&S to gross plant, measured in nominal terms. Across the sample of utilities, the average of the beginning and ending amounts for M&S are divided by gross plant, also measured as the average of the beginning and ending balances for year 2013. The sample of utilities include Duke Energy Indiana and Kentucky; Entergy Arkansas, Louisiana, and Mississippi; Kentucky Utilities, Gulf Power, Louisville Gas and Electric Mississippi Power, Old Dominion, and South Carolina Electric and Gas.

2019, based on the settled prices for July 2019, as observed for January 5, 2016 on the Chicago Mercantile Exchange (CME Group).[19] U.S. futures prices are exchange rate adjusted.[20] Costs for transportation are accounted for.

Operating costs comprise direct operating expenses including both fixed and variable costs (O&M), indirect administrative and general expenses (A&G), and insurance charges (Ins). Fixed and variable O&M is based on the Company's estimates, equal to $11.73/kW-year for an installed unit. The average level of A&G expenses is equal to 64.14% of direct operations and maintenances for NLH, estimated over years 2008-2014. Marginal A&G is likely to be substantially less than average A&G because of economies of scale across many of the various support functions and activities which constitute A&G; a review of the Company's recent resource cost history tends to confirm this result. For the immediate study, marginal A&G expenses are set accordingly: one half the Company's average A&G cost level. Insurance costs are set equal to 0.1% of the carrying charges on the Company's CT investment and incremental general and common plant.[21, 22]

Stated on a $/kW-year basis, the capital-related charges total to $138.71 and operating expenditures total $17.76, obtaining a total cost of $156.47/kW-year. The recognition of a reserve margin of 15% adds further to capacity costs in the amount of $23.86/kW-year; similarly, expected forced outage rates (EFOR) of 7% amounts to $13.76/kW-year. Altogether, the estimate of marginal generation capacity cost for NLH during 2019 is $193.48/kW-year.

This marginal capacity cost estimate reflects an installed all-in cost result and may not, for several reasons, necessarily satisfy least-cost supply requirements. First, generation supply for modest-sized power systems often confront a certain conundrum in resource sizing: generation is installed in lumpy increments of physical capital; thus, supply is highly indivisible. Yet, adherence to long-run cost minimization principles suggests that it is appropriate to install capacity additions in sizable increments in order to realize economies of scale in the process of construction and installation. As a consequence, however, supply-demand balance equilibria may not be fully satisfied during the near-term years

[19] For many years, futures contracts for oil and other commodities traded on New York Mercantile Exchange (NYMEX) were often referenced and used as the basis of expected market prices. NYMEX merged with the Chicago Mercantile Exchange to form CME Group in 2007.

[20] The adjustment reflects the average 2015 Canadian-US exchange rate of 1.2888, as reported by the Federal Reserve Bank of St. Louis.

[21] Arguably, insurance costs should cover both materials and supplies as well as fuel inventory.

[22] Substantial quantitative analysis is associated with estimates for A&G and general plant. This work involves the simulation of the real capital stock and real operations and maintenance costs including A&G for NLH over years 1997-2014. This analysis reaches further back, referencing historical cost and service level records from the late 1960s; incorporates Handy Whitman cost indexes relevant to Canada based on estimates of purchasing power parity, and takes account of capital depletion based on a geometric decay function. The simulation of the real capital stock was alternatively estimated using historical exchange rates, and historical cost indexes for Canada's electric power sector, obtained from Statistics Canada.

following installation. Specifically, near-term years may very well constitute a *capacity-long* condition, where the incremental costs of generation capacity exceed marginal reliability costs, measured in terms of outage costs associated with expected loss of load.

A capacity-long condition is expected to hold for NLH during 2019: the NLH power system is not expected to fully utilize 50MW of capacity (two 25MW CTs) to satisfy peak load reliability requirements, even though such additions may well prove appropriate in terms of least total costs over extended years. Accordingly, the immediate study adjusts the all-in cost estimate of generation capacity for NLH downward by 60%, ($118.00) in order to better match load-related reliability requirements for 2019. The end result, for purposes of the Company's 2019 marginal cost study, is generation capacity cost of $77.39/kW-year.

To summarize, the computation of the 2019 marginal generation capacity costs for NLH (Model 1) is shown below:

Table 7: Estimate of the Marginal Cost of Generation Capacity, Newfoundland-Labrador Hydro, 2019 (CAD/kW-year)

Estimate: 2019 Marginal Cost of Generating Capacity
Newfoundland-Labrador Hydro

Investment Cost ($/kW)	Parameters	Investment Costs per kW	Charges on Capital ($/kW-year)
Direct Facility Investment		2,123.7	124.04
General/Common	6.76%	143.55	10.49
Materials and Supplies	2.24%	47.57	2.78
Fuel Inventory		22.92	1.34
Working Capital (%/FOM)	6.16%	0.95	0.06

Charge Rates (%)	Parameters		Cost Elements ($/kW-year)
Carrying Charges, Direct	5.84%		128.22
Carrying Charges, Gen/Com	7.31%		10.49
Insurance Costs	0.10%		2.27
FOM Rate ($/kW-year)	11.73		11.73
A&G Cost Rate (% OM)	32.1%		3.76
	All-In Total Cost/kW-year:		**156.47**
Costs of Reserves (% of Supply)		15.00%	23.47
Cost Effect of E(Forced Outage)		7.00%	13.54
Adjustment for *Capacity-Long* Condition:			(116.09)
	Marginal Cost of Generation Capacity at Bus Bar ($/kW-year)		**77.39**

5.1.2.2 Market-Based Capacity Costs (Opportunity Costs, Model2)

Unbundled wholesale electricity markets, organized under the auspices of regional transmission groups, referred to as either Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs), obtain highly granular market prices, by type of service [23] and by timeframe and location. Within the U.S., unbundled electricity markets can assume either of two general types including *Energy Only* and *Energy plus Capacity* configurations. Both markets involve highly structured procedures to determine market prices for the relevant generation services. While there are a number of nuances associated with the design of auctions, electricity auctions involve two general types including *uniform price sealed bid* auction design for energy markets and, for capacity, *uniform price sealed bid multi-round* and *descending clock* auction structures.

As alluded to, much of the regional wholesale electricity markets of North America are organized under the auspices of RTOs. RTO markets integrate generation and transmission services. Moreover, the procedures to determine prices for services – the process of price discovery – under RTOs are remarkably different from that of contract path market regimes. In the case of RTOs, prices are determined through formal auction procedures; in contrast, the provision for price discovery under contract path markets is often limited to largely informal over-the-counter procedures or, for longer-term transactions, sealed bid discriminatory auctions.

Under an Energy Only market structure, the marginal cost of generation capacity is implicitly financed by the scarcity rent content in prices. The working premise underlying Energy Only markets presumes that wholesale electricity prices for energy, along with reserves, would clear at levels above the running costs of the marginal generator during peak load periods in order to cover capacity costs. Over the course of an annual period, the scarcity rent content within energy prices, summed across hours, would be sufficient to cover the marginal cost of capacity. This view holds that the competitive process would obtain, across multiple suppliers, an aggregate level of installed capacity which would result in sufficient scarcity rents to cover capacity on a going forward basis. Too much capacity begets comparatively low prices, causing suppliers to shed capacity. Too little capacity results in comparatively high prices and improved profitability through higher scarcity rents; in turn, generation suppliers install more capacity up to the point that the total scarcity rent content is closely balanced to capacity costs – an equilibrium condition. Scarcity rents constitute the shadow price of the marginal cost of capacity and, conceptually,

[23] Service types include electric energy, voltage control and reactive power, operating reserves including regulation, spin and non-spin reserves, transmission congestion and line losses (reflected as differences in locational energy prices). Prices are determined with hourly frequency for same-day and day-ahead timeframes (referred to as dual settlements) and for numerous locations within transmission networks. In the case of the Midcontinent ISO (MISO), for example, hourly locational marginal cost-based prices (LMP) are solved for over 2,440 buses which, in turn, are aggregated into hub and zonal prices.

are not far removed from consumer outage costs providing that organizing agents of markets, the RTOs, set planning-based reserves for generation capacity at appropriate levels – perhaps 12-15%.[24]

The fundamental difficulties with Energy Only markets are twofold. First, regulatory authorities tend to cap the prices (price or bid caps); thus, energy prices are not allowed to clear at unconstrained high levels. Because it is the high prices, realized during timeframes of limited supply, which contain much of scarcity rent content over annual timeframes, generators often may not cover total capacity costs stated on an all-in cost basis. Second, historical evidence demonstrates that scarcity rent content within energy prices varies greatly from one year to another. As a consequence, generation suppliers have been exposed to considerable risk of not covering capacity costs.[25] The reasons for sizable departures from well-balanced supply-demand conditions are several – weather, performance of the macro-economy, and unexpected changes in demand as a result of market entry by renewable resources, to name a few.

In brief, high year-over-year variation in scarcity rent content along with constraints on price levels can result in chronic revenue shortages to cover capacity costs. Thus, capacity auctions have been organized in the Eastern RTOs including New England, New York, and PJM.[26] These auctions can be for both short-term forward periods in the case of the Installed Capacity (ICAP) market of the New York ISO, or for longer-forward periods, up to four years in advance of installed commercial availability.

Capacity auctions may involve several rounds of price determination, thus allowing participants to delist and to adjust positions and, for the market as a whole, ultimately reaching market equilibrium price levels. Generators accepted in capacity auctions have bid prices equivalent to or below the relevant market-clearing prices, which are specific to territorial zones within RTO footprints. Winning generators (those within the auction solution) are compensated at the market clearing auction price ($/kW-year). Auction price results reflect levels of compensation that closely approximate the all-in incremental costs (cost of new entry or CONE), net of the revenues that a pure peaking generator would realize from participating in energy and ancillary services markets.

Prices for capacity are determined by the intersection of supply and demand curves associated with generation capacity. The supply function is the extant set of offers: the MW quantities and associated offer prices advanced by the resources participating in capacity auctions. The demand curves are

[24] For a more complete discussion, please reference *Ensuring Adequate Power Supply for Tomorrow's Electricity Needs*, Mathew Morey, Laurence Kirsch, Kelly Eakin, and Robert Camfield, June 16, 2014, published by the Electricity Markets Research Foundation.

[25] Supply-demand equilibrium is obtained when the marginal costs of capacity ($/kW-year) are equal to marginal outage costs, equal to the product of expected unserved energy (EUE) and value of lost load (VOLL) to retail consumers. Contemporary surveys suggest that VOLL resides within the range of $3.00 to $12.00 per kWh, for most economic sectors. A well-known Canadian researcher, Roy Billinton, has published numerous studies which report outage cost survey results.

[26] Reference *Centralized Capacity Market Design Elements*, Commission Staff Report AD13-000, August 23, 2013, Federal Energy Regulatory Commission.

administratively estimated by the RTOs, determined according to the expected level of realized reliability at various levels of installed capacity: as simulated, consumer outage costs decline rapidly with progressively higher levels of installed capacity. Capacity auctions are typically held for market zone within the territorial footprint of the RTO. In the event of failure to perform – e.g., failure to start when called by system operators – accepted resources may be penalized and may be liable to pay for replacement capacity.

The Forward Capacity Market (FCM) of the New England ISO has a mandatory centralized capacity market. The auction for new capacity together with existing capacity satisfies the Installed Capacity Requirement (ICR). The capacity auction results in guaranteed capacity prices for up to five years.[27] The FCM auction begins at fairly high prices, thus yielding more capacity than the ICR. Over the course of the various auction rounds, capacity prices are steadily reduced under the structure of the declining clock auction procedures. Market clearing capacity prices are settled once the ICR requirements of each zone are satisfied. Existing capacity resources are price-takers, clearing the auction automatically;[28] of course, new capacity resources must provide quantity and price bids in order to ultimately receive capacity-based compensation. Capacity and capacity prices are differentiated by zone. Load serving entities (LSEs) can bilaterally trade capacity for up to three years in advance.

The cost of new entry (CONE) for the New England ISO Forward Capacity Market involves several cost elements for the *Gross Cone* and *Net Cone* cost benchmarks. The gross cost of new entry is computed as:

$$C_{gross} = K + FOM$$

where,

K = capital cost ($/kW month)[29]
FOM = fixed O&M cost ($/kW month)

The Net Cone cost benchmark is computed as:

$$C_{net} = C_{gross} – E – AS – PFP/PER$$

where,

E = revenues earned from the energy market
AS = revenues earned from the ancillary services markets
PFP/PER = revenues (or costs, in which case the values are negative) associated with the Pay for Performance program and Peak Energy Rents

[27] New York auction procedures include voluntary monthly and six-month auctions for summer and winter timeframes, referred to as "capability period". Offers by capacity suppliers include quantities (MWs) and prices; offers are accepted up to the point that the resulting supply curve satisfies the demand for capacity, as determined with planning simulation tools. Load Serving Entities (LSEs) are allowed to self-supply capacity obligations. Capacity and capacity prices are differentiated by zone. As with New England, load serving entities (distributors) trade capacity up to one month in advance.

[28] Existing capacity resources can influence the market clearing price by exiting the auction, referred to as delisting.

[29] The benchmark capital costs are estimated for specific CT generators including, for example, the LM6000 series or Frame 7 series combustion turbo generators of General Electric.

The net cone value is used to determine the inflection point, where the demand for capacity is downward sloping to the right.

The New England ISO's most recent auction under the Forward Capacity Market covers the market's installed capacity requirements (ICR) for forward year 2019.[30] The auction was conducted on February 10, 2016, covering the NE ISO system as a whole as well as several transmission interfaces, each separately recognized. The interfaces included the New York ISO interfaces of the Cross Sound Cable and the NY ISO-NE ISO bundle of Tie Lines; New Brunswick; and Hydro Quebec interfaces of Phase I/II and High Gate. Auction price results were announced on the following day February 11,[31] and are as follows:

Table 8: Capacity Auction Price Results, New England ISO for 2019, USD/kW-year

	System Wide Capacity Auction Price	Interfaces with NE ISO	
		All Other Interfaces	New Brunsick Link
Round 1	$17.30-$14.50	Eq Price	Eq Price
Round 2	$14.50-$11.50	Eq Price	Eq Price
Round 3	$11.50-$8.50	Eq Price	Eq Price
Round 4	$8.50-$5.50	Eq Price	Eq Price
Round 5			$5.50-$2.75

"Eq Price" refers to interface prices equivalent to the system-wide capacity auction price.

The above system-wide auction result, $5.50-$2.75 translates into an annual price of approximately $48.00/kW-year,[32] stated in USD or, equivalently, $58.18/kW-year in Canadian dollars. The capacity auction price is not adjusted for the expected forced outage rate (EFOR) or capacity reserves (≈15%). Insofar as the relevant marginal cost is the differential of total costs with respect to Island and Labrador loads, these adjustments are appropriate: accounting for EFOR obtains a marginal generation capacity cost of $62.55/kW-year; incorporation of planning reserve margins results in a marginal capacity cost of $71.94/kW-year.

5.2 MARGINAL TRANSMISSION COSTS

Marginal transmission costs, like generation, include energy and capacity components, where energy costs are in the form of physical losses, expressed as a percent of load. Marginal transmission losses include the charges for losses within the two transmission paths to Northeast markets, NE ISO, and NY ISO. Each transmission cost component is reviewed below.

[30] Reference *Parameters for the Tenth Forward Capacity Auction (FCA #10) Capacity Commitment Period 2019-2010*, New England ISO, July 2015.

[31] Reference *Forward Capacity Market (FCA 10) Result Report*, New England ISO, February 11, 2016.

[32] Based on a close-to-midpoint value of $4.00/kW-month.

5.2.1 Marginal Energy Costs, Transmission (Line Losses)

Marginal energy costs for transmission are the physical energy losses within transmission networks. Physical losses include charging losses and thermal losses, often referred to as I^2R losses, where *I* refers to electrical current flows within circuits, and *R* refers to resistance of the physical mass and related characteristics of conductors. Charging losses are associated with conductors and transformers and do not change with respect to load levels.

It is perhaps useful to clarify key factors that determine transmission losses, which occur predominantly in the conductors that constitute transmission lines, as follows:

- Power system losses vary with respect to temperature: total and average losses decline under lower ambient temperatures, other factors constant.
- Transmission losses are predominantly thermal losses, resulting from line resistances. Larger conductors will generally have lower losses.
- Transmission losses decline significantly with higher conductor voltages, as currents are lower by similar magnitudes.
- Line losses are approximately linear with respect to the length of conductors.

Most important for the purpose of the immediate study: Thermal losses change non-linearly with respect to changes in the level of loads on circuits. Specifically, marginal losses rise at twice the rate of change of load within power circuits. In support of the Study, the Company conducted a sizable set of load flow simulations covering selected seasons and load conditions, including *Winter: Peak, Moderate, and Off-Peak Loads*; *Spring-Fall: Peak and Off-Peak Loads; Cool-Summer: Peak and Off-Peak Loads*; *Warm-Summer: Peak and Off-Peak Loads*.[33] Each season and load condition is assessed for *Baseline*, *+1%*, and *-1%* cases – 27 cases in all. The load flow cases designated as *+1* and *-1* refer to the percentage change in load level with respect to the corresponding baseline case. Marginal losses are estimated by gauging the change in total losses across the cases (*Baseline, +1, -1*).[34] For the load difference cases (*+1, -1*), net power flows out (exports) of the NLH power system are held constant: load changes are exclusively in the form of differentials in power withdrawals from the Company's 66-138kV system. Across all cases, the marginal generator is located at NLH's new generation facility, Muskrat Falls.

[33] *Winter* season refers to the second half of November and December – March; *Spring/Fall* season refers to April, the first half of May, the second half of September, October, and the first half of November; *Cool-Summer* season refers to the second half of May, June, and the first half of September; Warm-Summer refers to July and August.

[34] Note that the true marginal losses are derivatives of underlying power flow solution, and will be somewhat above the losses calculated as change case differentials.

Table 9: Load Flow Estimates of Incremental Losses for the NLH Transmission Network, for Selected Season and Load Scenarios

System Wide Incremental Power Losses
Differences from Baseline Cases

Winter		+%1	-1%
	Peak	8.33%	12.75%
	Moderate	15.48%	13.33%
	Off-Peak	5.79%	8.26%
Spring/Fall			
	Peak	11.48%	17.70%
	Off-Peak	5.88%	9.91%
Cool Summer			
	Peak	18.18%	16.28%
	Off-Peak	4.17%	8.45%
Warm Summer			
	Peak	9.78%	10.11%
	Off-Peak	5.36%	5.56%

The load flow studies[35] reveal markedly different loss levels with respect to season and load level. Specifically, percentage losses do not necessarily decline significantly during off-peak summer periods, though retail loads of the NLH power system vary significantly between the winter peak periods and the summer off-peak season. Sizable power flow withdrawals at the Bottom Brook network location within the Island system alter the longstanding winter peak-summer off-peak load differences. While summer domestic loads are at comparatively low levels, export sales through Nova Scotia, served by either Island generation or Muskrat falls, increase flows on lines during off-peak seasons. On an expected value basis, Nalcor Energy anticipates that Island resources will often serve exports to NE ISO, in which case marginal and average losses are at moderate levels. On occasion, however, Muskrat Falls may serve as the marginal source of generation, where power flows southeast across the Labrador Island Link to Soldier's Pond situated on the Avalon Peninsula, and then west to Bottom Brook. Differences in line losses across load flow scenarios are as follows:

(reference following page)

[35] The results shown above incorporate modifications to the load flow cases in to order to appropriately take account of expectations of differences in dispatch patterns to accommodate non-domestic loads. The result is improved estimates of marginal line losses with respect to changes in domestic loads – which is the relevant context for the immediate study.

Table 10: Estimated Loads, Exports, and Island High Voltage Line Losses for Peak and Off-Peak Seasons during 2019, NLH Power System

Selected Baseline Load Flow Case Results (MW)			
	Avalon Loads	Exports Sales	Losses, Island 230kV Network
Muskrat Falls on the Margin			
Winter Peak	821.6	158.0	22.9
Winter Off Peak	524.6	158.0	12.0
Warm Summer Off-Peak	272.3	500.0	39.2
Bay D'Espoir on the Margin			
Cool Summer Peak	510.9	158	15.6
Cool Summer Peak	508.9	250	22.6

As shown above, line losses within the Island AC 230kV network can, under selected circumstances, rise during the off-peak summer season, reaching sizable levels. Though retail loads for summer decline, total loads may not be significantly lower in certain regions of the NLH network. Importantly, the power loading on lines within the Island AC high voltage system west of the West Avalon substation; because of the long distances – approaching 500 kilometers – losses can be above that of the winter season.

For purposes of marginal costs contained in the immediate study, line losses are estimated using the well-known I^2R approximation. Specifically, the analytics underlying the hourly marginal cost estimates are parameterized such that the marginal losses, averaged across hours, approximate – but are somewhat below – load flow results, notwithstanding load flows for the cold summer season. Specifically, marginal line losses for peak and off-peak hours are as follows:

Table 11: Parameterized Peak and Off-Peak Marginal Loss Percentages, Estimates for the NLH Power System, 2019

Marginal Loss Percentage					
Month	**Peak**	**Off Peak**	**All-Hours**	**Max**	**Min**
Jan	12.4%	11.0%	11.7%	14.4%	8.9%
Feb	12.7%	11.6%	12.1%	14.4%	9.6%
Mar	12.3%	12.2%	12.2%	14.6%	10.2%
Apr	12.2%	10.8%	11.5%	14.0%	9.3%
May	9.3%	8.4%	8.9%	11.3%	6.9%
Jun	9.3%	6.8%	8.1%	10.3%	5.8%
Jul	9.5%	6.5%	8.3%	10.2%	5.5%
Aug	9.1%	6.3%	7.9%	9.7%	4.9%
Sep	9.4%	6.8%	8.2%	10.9%	5.6%
Oct	10.1%	8.4%	9.3%	11.3%	6.8%
Nov	10.5%	9.6%	10.0%	12.6%	7.3%
Dec	11.9%	9.2%	10.6%	14.4%	6.2%
Annual	10.9%	9.4%	10.2%	14.6%	4.9%

As shown, marginal line losses average 10.2%, and reach a maximum of slightly above 14% and a minimum of just less than 5%. Compared to the load flow results, the hourly marginal cost model is calibrated to obtain closely approximate but somewhat lower marginal line losses for two reasons: the load flow studies reflect exceptionally high and low load levels, and are not necessarily reflective of typical load levels of peak and off-peak timeframes across seasons. Second, the native loads of the Island are concentrated on the Avalon Peninsula; consequently, the high levels of average and marginal losses within the AC high voltage system west of West Avalon are less impacted. In essence, a change in load on the Avalon Peninsula is not likely to precipitate marginal losses, measured in percentage terms, at the loss levels obtained in the load studies for the west of West Avalon network.

5.2.2 Marginal Transmission Capacity Costs

The key features of transmission capacity costs are twofold: First, transmission networks are characterized by very large economies of scale: the differences in flow capability between 115kV and 230kV lines can approximate four times, while cost differences may be measurably less – e.g., a factor of 1.5 times – other factors constant. Second, transmission capacity costs, measured in load capability (MWs), change more-or-less one-to-one with respect to transport distances.[36]

Marginal transmission capacity costs are, by definition, load-related costs: the change in total (transmission) costs with respect to a change in load-carrying capability (MW). Over years, however, ongoing investment in transmission is a function of reinvestment (replacement) and, particularly in recent years, upgraded reliability, unrelated to load level. While transmission capability is, often, more stressed during high load periods, power system outage events often take place during moderate load levels, industry history suggests.

Like generation, the marginal capacity cost of transmissions is stated on a $/kW-year basis. For the immediate study, marginal transmission capacity costs are based on forward-looking costs and load changes. The starting point is the Company's estimated budget expenditures associated with NLH transmission expansion plans and estimated growth in peak loads for years 2018-2023. Properly executed and appropriately attenuated, this *change in cost-change in load* approach for estimation obtains plausible transmission marginal cost estimates.

The Company's expected budget expenditures follow directly from transmission plans which, in turn, are driven by the near-term capital plans for three categories of facility needs, including:

- Replacement of aging transmission facilities (replacement);

[36] The main exception to the relationship between distance and total costs is voltage: comparatively long AC transmission lines require voltage support in the form of series compensation-providing technology such as static capacity banks placed along the circuits of long transmission lines in order to manage the inductive capacitance inherent to the facilities.

- Reliability updates to existing network facilities in order to conform to reliability criteria; and,
- Increased capacity to satisfy expected changes in peak demands.

These categories of capital expenditures for transmission are not completely separable. Ratings of transmission lines to handle load is not exclusively determined by voltage; conductor size, conductor material, voltage support over extended distances, and span lengths all contribute to the overall capability transmission circuits, expressed as line ratings. As a consequence, replacement of existing facilities with new equipment often results in improved reliability and, to a lesser extent, increased load carrying capability; this holds true for reliability driven expenditures. As an example, investment in equipment such as static var compensators (SVC) may provide for improved transient stability. But because networks are somewhat more susceptible to transient events during high-load levels, capacity benefits are also obtained. Nonetheless, for purposes of marginal cost analysis – i.e., the *change in cost-change in load* paradigm – load-related transmission expenditures by the Company, as planned over 2018-23, serve as the *cost basis*. Similarly, the Company's forecast path for peak loads for the integrated Island-Labrador system over these years serves as the *load basis*.

Stated on $/kW-year basis, estimates of transmission capacity costs are not specific to any single transmission facility or expenditure, but may include several facilities and a number of individual expenditures over the relevant years. In this respect, load-related transmission capacity cost can be described as an average of incremental expenditures and costs. More specifically, the marginal cost of transmission capacity is determined as follows:

$$\begin{aligned} &Capacity\ Cost_{Trans} \\ &\quad = \left(I_{Trans} + I_{M\&S_{TR}} + WK\right) * ECC_{Trans} + I_{GP} * ECC_{GP} + OM_{Trans} \\ &\quad + A\&G_{wrt\ OM} + Ins_{K,Ops} \end{aligned}$$

where,

$Capacity\ Cost_{Trans} = total\ annual\ direct\ and\ indirect\ cost\ of\ transmission$

$I_{Trans} = direct\ investment\ expenditure, transmission$

$I_{GP} = investment\ expenditure\ in\ indirect\ plant\ and\ equipment$

$I_{M\&S_{TR}} = investment\ expenditure\ for\ materials\ and\ supplies\ inventory, transmission$

$WK = working\ capital\ associated\ with\ FOM$

$ECC_{Trans} = economic\ carrying\ charge\ rate, transmission$

$ECC_{GP} = economic\ carrying\ charge\ rate, general\ plant$

$OM_{Trans} = annual\ expenditure\ for\ operations\ and\ maintenance$

$A\&G_{wrt\ OM} = annual\ expenditure\ for\ administrative\ and\ general\ expenses$

$Ins_{K,Ops} = annual\ expenditure\ for\ insurance, plant\ and\ operations$

The structure of the $/kW-year estimate of transmission capacity cost is highly similar to the methodology utilized to determine the internal cost of generation capacity, and includes carrying charges on capital and operating costs. Capital-related cost is equal to the sum of the direct investment expenditures, general plant, materials and supplies (M&S), and working capital, multiplied by the carrying charge rate.

The carrying charges are based on the *economic carrying charge* approach, sometimes referred to as *trended real capital costs*. As described earlier, the economic carrying charge (ECC) method essentially captures the expected escalation in the costs of new investment over time; under the condition of rising costs for new physical facilities, as expected, economic carrying charges rise accordingly over the life of the facilities.[37] ECC-based charges rise with respect to shorter capital life. For this reason, the ECC rate for general plant is substantially higher than the ECC rates for either generation or transmission capacity.

Estimates of incremental investment in general plant associated with marginal transmission capacity, follows the same methodology used to determine estimates of the internal cost-based generation capacity. Restated, estimates of incremental investment for general plant costs are drawn from the historical relationship between NLH's capital investment in general and common plant and investment in generation and transmission facilities for years 2008-2014, net of economic depletion (depreciation) and measured in real terms. The materials and supplies inventory associated with transmission is based on the level of materials and supplies associated with gas-fueled generation, for a sample of several modest-sized U.S. electricity utilities during 2013 (listed previously in footnote 8).

Operating costs for transmission, similar to generation, include the annual direct operating expenses, indirect administrative and general expenses (A&G), and insurance charges (Ins). Fixed O&M is based on a historical assessment of the Company's O&M expenditures with reference to the real capital stock, for transmission assets. As previously mentioned, the development of the real capital stock draws on the Company's energy sales experience reaching back to the late 1960s, and gross and net plant records over years 1997 – 2014. For years 2008-2014, O&M costs per unit of real capital stock are equal to 3.03% – a result which largely conforms to the cost experience of other electric utilities. As discussed before, A&G expenses are measured with respect to direct O&M and stated on an *average A&G rate of cost basis*, are equal to 64.14%, an analysis result estimated, also, over years 2008-2014. As discussed earlier, marginal A&G is likely to be substantially less than average A&G[38] and, for the immediate study, marginal A&G expenses are set accordingly: one half the Company's average A&G cost level. As mentioned within the discussion of generation, Insurance costs are set (parameterized) at a level of 0.1% of the carrying charges on investment in physical facilities, including general and common plant.

[37] An exception to this general rule is to account for scale economies and productivity within production processes. In the case of electricity, productivity, as typically measured, appears to be near zero or declining for the industry as a whole, over recent years.

[38] This is a consequence of substantial economies of scale which are often availing for the many support functions and activities within A&G; a review of the Company's recent resource cost history tends to confirm this result.

Estimates of the marginal cost of transmission capacity are presented below. Note that the direct transmission investment cost, $412.97, is set equal to 40% of the incremental load-related investment costs for study years 2018-2023. In other words, the calculated result is attenuated in order to account for two major factors: capital indivisibility common to electricity facilities and, second, the impacts of scale economies in transmission. In brief, for these forward years, the Company does not anticipate that the prospects for growth in peak loads will be sufficient to fully utilize the *planned-for* expansion of capacity, in transmission. The capacity adjustment, equal to a downward adjustment of $58.53/kW-year, is similar to the adjustment for generation.

To summarize, the estimate of the marginal cost of transmission capacity is as follows:

Table 12: Estimate of the Marginal Cost of Transmission Capacity, Newfoundland-Labrador Hydro, 2019 (CAD/kW-year)

Investment Cost ($/kW)	**Parameters**	**Investment Costs per kW**	**Charges on Capital ($/kW-year)**
Direct Facility Investment		1,032.42	48.11
General/Common	6.76%	69.79	5.10
Materials and Supplies	0.72%	7.43	0.35
Working Capital (% OM)	6.16%	2.63	0.19

Charge Rates (%)	**Parameters**	**Cost Elements ($/kW-year)**
Carrying Charges, Direct	4.66%	48.65
Carrying Charges, Gen/Com	7.31%	5.10
Insurance Costs	0.10%	1.10
FOM Rate ($/kW-year)	3.13%	32.33
A&G Cost Rate (% OM)	32.1%	10.37
Total Costs ($/kW-year)		97.54
Adjustment for *Capacity-Long* Condition:		(58.53)
Marginal Cost of Transmission ($/kW-year)		**$39.02**

As shown above, the proposed cost attenuation reduces the marginal cost of transmission capacity from $97.54/kW-year to $39.02/kW-year.

6.0 CONCLUDING COMMENTS

The restructuring of electricity resources currently underway assumes two overarching dimensions: Newfoundland-Labrador Hydro's (NLH) power system will be largely integrated, thus drawing upon a common pool of generation resources with thermal capacity assuming a smaller role; the Island system will be interconnected to the Eastern Interconnection, facilitating wholesale market participation. As a consequence, the level and pattern of economic costs will be measurably altered. First, marginal energy costs (and reserves) will be determined by market value, rather than internal costs – with the market value the lesser of internal costs in virtually all timeframes. Second, transmission will play a much more prominent role in day-to-day operations, market transactions, and resource decisions over long-term forward periods.

The Company's immediate study of marginal costs for 2019 is conceptually well founded, technically articulate, and resides empirically on the best information available – which should be updated periodically. Accordingly, the 2019 study results can be used for the purposes intended: analytical basis for cost allocation, resource evaluation, and tariff prices geared to obtain gains resource efficiency. Moreover, the analytics underlying the study are well suited to further development such as extension over forward timeframes beyond 2019 in a manner that accounts for (i.e., explicitly models) risks inherent to the future worth of resources.

At a technical level, we wish to conclude with a few comments, as follows:

1. *Attenuation of Capacity Costs to Account for Capacity-Long Condition:* Though it is often appropriate to fully invest in larger-sized facilities because of economies of scale, such resource decisions can gives rise to an inherently capacity-long condition over near-term years. For this reason, and because the purpose of the study is to provide guidance for the development of appropriate price signals over the long term, it is appropriate to attenuate calculated capacity costs on a $/kW basis to better reflect the long-term supply-demand balance wherein expanded capacity can be more fully utilized. Accordingly, it is appropriate for Newfoundland-Labrador Hydro to consider the attenuation of marginal capacity costs for both generation and transmission within marginal costs covering contemporary years – note that the marginal cost of generation capacity internal to NLH, as attenuated, is not far from market value. Going forward, we can anticipate that the appropriate degree of cost attenuation will likely decline as the NLH power system can more fully utilize the installed capacity. This can be explored through scenario analysis, benchmarked to model results obtain from formal generation planning tools.

2. *Line Losses Subject to Further Analysis:* As discussed, the parameters for line losses, incorporated within the marginal costs reported herein, are drawn from load flow studies. NLH line losses appear to be sensitive to line loading within the Island high voltage AC network. To this end, we recommend that NLH explore further line loss estimates, for purposes of marginal costs. Also, with the appropriate load flow parameters, an hourly algorithm can applied to selected periods within the annual 2019 timeframe.

3. *Projections of Marginal Energy Costs:* The marginal energy costs consist of a single vector of hourly marginal energy prices (marginal cost of energy) for Northeast markets, including

markets operated by the NE ISO and the NY ISO. The vector of estimated prices is plausible. NLH may wish to commission further analysis, obtaining a set of projected prices in order to capture uncertainty associated with the worth of resources.

4. *Parameterization:* The marginal cost estimates are generally sensitive to wholesale markets and underlying system conditions. Through the parameterization of marginal cost models, it is useful to explore sensitivities, in order to more fully understand and capture inherent uncertainty over future timeframes. NLH may wish to explore the sensitivity of projections of estimates of marginal costs.

APPENDIX A

SPECIFICATION OF MARGINAL COST MODELS, NEWFOUNDLAND-LABRADOR HYDRO

MODEL #1

$$M\_Cost_h^{NLH,J} = \left(MEP_h^{market\ J} + MRP_h^{market\ J}\right) * LF_{Path\ J} * LF_h^{NLH} + MC_{G\_Cap_h}^{AP} * LF_h^{AP} + M_{T\_Cap_h}^{NLH}$$

where,

$MEP_h^{market\ J} = marginal\ energy\ price, hour\ h, market\ J$

$MRP_h^{market\ J} = marginal\ reserve\ price, hour\ h, market\ J * operating\ reserve\ \%^{NLH\ System}$

${M_{G\_Cap}}_h^{AP} = marginal\ generation\ capacity\ cost_{kW-year}^{Avalong\ Peninsula} * allocation\ factor_h^{Gen\_Cap^{AP}}$

${M_{T\_Cap}}_h^{NLH} = marginal\ transmission\ capacity\ cost/_{kW-year} * allocation\ factor_h^T$

$LF_{Path\ J} = \left(1 - loss\ percentage_{Path\ to\ Market\ J}\right)$

$LF_h^{NLH} = \left(1/\left(1 - marginal\ losses\ percentage_h^{NLH\ System}\right)\right)$

$LF_h^{AP} = \left(1/\left(1 - marginal\ losses\ percentage_h^{Avalon\ Peninsula}\right)\right)$

$Allocation\ Factor_h^{Gen\_Cap^{AP}} = generation\ cost\ allocation\ share, hour\ h$

$Allocaiton\ Factor_h^T = transmission\ cost\ allocation\ share, hour\ h$

Regions, Paths:

$J = 1\ for\ Quebec\ to\ New\ York\ ISO; 2\ for\ Nova\ Scotia/New\ Brunswick\ to\ New\ England$

MODEL #2

$$M\_Cost_h^{NLH,J} = \left(MEP_h^{market\ J} + MRP_h^{market\ J} + G\ A\_Price^{market\ J}\right) * LF_{Path\ J} * LF_h^{NLH} + M_{T\_Cap_h}^{NLH}$$

where,

$MEP_h^{market\ J} = marginal\ energy\ price, hour\ h, market\ J$

$MRP_h^{market\ J} = marginal\ reserve\ price, hour\ h, market\ J * operating\ reserve\ \%^{NLH\ System}$

$G\ A\_Price^{market\ J} = generation\ auction\ price, market\ J$

${M_{T\_Cap}}_h^{NLH} = marginal\ transmission\ capacity\ cost/_{kW-year} * allocation\ factor_h^T$

$LF_{Path\ J} = \left(1 - loss\ percentage_{Path\ to\ Market\ J}\right)$

$LF_h^{NLH} = \left(1/\left(1 - marginal\ losses\ percentage_h^{NLH\ System}\right)\right)$

$Allocation\ Factor_h^T = transmission\ cost\ allocation\ share, hour\ h$

Regions, Paths:

$J = 1\ for\ Quebec\ to\ New\ York\ ISO; 2\ for\ Nova\ Scotia/New\ Brunswick\ to\ New\ England$