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December 29, 2015

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**

Attached please find Part I of Newfoundland-Labrador Hydro's (Hydro) report with respect to marginal costs, prepared by Christensen Associates Energy Consulting.

Part I of Hydro's marginal cost report focuses on methodology. The discussion provides a fairly detailed review of methodology options, and identifies the methods that are being adopted by Hydro, for purposes of estimating marginal cost during 2019. Part I will be followed by Marginal Cost Report Part II, which will further discuss methodology and its application, and will present estimates of marginal costs of the Hydro power system for 2019. Hydro intends to file Part II of the marginal cost report with the Board during the week of January 18, 2016.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Kevin J. Fagan
Manager, Rates and Regulation

KJF/bs

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 I

METHODOLOGY: ESTIMATION OF MARGINAL COSTS OF GENERATION AND TRANSMISSION SERVICES for 2019

prepared for:

NEWFOUNDLAND LABRADOR HYDRO

developed by:

CHRISTENSEN ASSOCIATES ENERGY CONSULTING
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December 29, 2015

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1.0 INTRODUCTION

This report reviews the proposed methods for the estimation of the marginal cost of generation and transmission services (G&T services) provided by Newfoundland and Labrador Hydro ("NLH" or "Company"). Marginal cost refers to the change in total costs associated with a change in the level of services provided. For infrastructure industries, electric power in particular, marginal cost is broadly recognized as the appropriate basis to value incremental resources used in the provision of services. For electricity services, viable estimates of marginal costs assume strategic importance, serving as the basis for short-and long-term resource decisions, cost allocation, and efficient tariff prices. As envisioned, NLH's estimates of marginal costs of G&T services will provide guidance for:

- the allocation of financial costs (revenue requirements) to industrial customers and power distributors (Newfoundland Power); and,
- design of wholesale tariffs for G&T services, where the end result is price incentives for consumers to use electricity efficiently.

Marginal costs reflect incremental costs incurred by NLH to produce and deliver electricity services, at the numerous delivery points across NLH's lower voltage transmission network, the 66kV-138kV network, where the Company's industrial customers and Newfoundland Power receive service. Marginal G&T costs will be estimated in hourly frequency for 2019, and will include energy and reliability cost components.

This report provides a brief review of marginal cost methodology, clarifies the proposed marginal cost estimation for NLH, and concludes with a summary of observations. Estimates of marginal costs for 2019 will be provided in a supplemental report, *Marginal Cost Report, Part II*, soon to follow.

2.0 MARGINAL COST METHODOLOGY

Marginal cost is the change in total cost with respect to a change in the level of output, where output refers to the production and delivery of goods and services. Marginal costs are highly specific to industry and underlying production technology, and the goods and services that are produced and provided. Generally speaking, the provision of retail electricity service is a bundle of upstream services, including:

- <u>*generation services*</u>, in the form of electric energy and reserves;

- *transmission services*, in the form of capacity to provide the long-distance transport of power (energy, reserves) between production locations (generator sites) and delivery locations, including power distribution[1] and large industrial consumers. Transmission services are provided by high voltage electrical networks, configured as either meshed[2] or radial circuits; and,
- *interconnection services* involving the electrical interconnection of generator sites, power distribution, and large consumers with the transmission network. Interconnection involves voltage transformation, often carried out at the various points of delivery. For NLH, this can include both large-scale pad mount transformers and associated control equipment, as well as large substations.[3]

Marginal cost analysis draws upon s*hort*- and *long-run* concepts.[4] The most relevant definition for costing and pricing electricity services is *Short-Run Marginal Cost* ("SRMC"), as estimated for either near real-time or forward periods. As a practical matter, however, short-run marginal costs for transmission and interconnection services are not readily observable, typically.[5] Thus, for these services, estimates of *Long-*

[1] Locations of power distribution would include substations where distributors such as Newfoundland Power take delivery of generation and transmission services.

[2] The term "meshed systems" refers to parallel path electrical systems where power flows from production locations to delivery locations over multiple paths, including single loop circuits and the many parallel paths that constitute vast interconnected networks such as those that make up the Eastern Interconnection.

[3] For estimation of marginal costs, *interconnection* may imply power transactions and the measurement and billing of both the quantities of supply (power generation) and quantities of demand (electricity usage by retail consumers).

[4] Short-run marginal cost is the change in short-run variable costs with respect to a change in load. Some costs remain unchanged in the short run, and are thus referred to as fixed costs. That is, the timeframe – *e.g.,* day ahead – is too short for physical facilities currently in place (the stock of physical capital) to be altered or adjusted. In the short run, the capital-related charges and fixed operations and maintenance costs (FOM) associated with physical facilities do not vary as load varies.

Under LRMC all costs including capital charges and FOM associated with physical resources vary in response to a change in load level. This means that, in the long run, a change in the expected load level precipitates adjustments to physical facilities in order to obtain the desired (least total cost) resource configuration and mix. In the context of the real world, long-run adjustments – *i.e.*, the implementation of adjustments to the resource pool in order to obtain the least cost configuration – may take a very long time, years or a decade. Indeed, the process of implementing long-run adjustments to realize the optimal configuration is likely to be taking place *as the optimal configuration is also evolving*. As a practical matter, then, the LRMC definition of marginal cost is most relevant as a conceptual view. In brief, LRMC is the change in total cost with respect to a change in load if all resources could be adjusted to the optimal configuration *overnight*.

In summary, the most useful marginal cost metric is forward-looking (*ex ante*) short-run marginal cost, where forward-looking SRMC embody expected long-run adjustments. Accordingly, the immediate discussion is confined to SRMC although capacity cost proxies, which are essentially LRMC adjustments to SRMC, are incorporated in the analysis. These cost proxies, in the form of marginal capacity costs are incorporated within SRMC as a surrogate for reliability costs, for both generation and power delivery (Transmission and Distribution, or T&D). Power delivery for the immediate marginal cost study is limited to transmission, however.

[5] The exception is unbundled locational electricity markets, wherein the short-run marginal costs of transmission is equal to the sum of the incremental impacts on locational prices (which incorporate marginal congestion and line

Run Marginal Costs ("LRMC") can often serve as viable proxies for forward-looking short-run marginal costs.

2.1 GENERATION SERVICES

Marginal generation costs consist of *energy* and *reserves*. Reserves provide additional capability to ensure that electricity services are provided with the appropriate level of reliability; hence, the marginal costs of reserves are associated with *marginal reliability costs*. *Marginal energy cost* refers to the incremental fuel and variable operating and maintenance costs associated with a change in load level.

Marginal Reliability Cost refers to the costs associated with unexpected power interruptions – the likelihood and magnitude of electricity demand not served because of power outages. Reliability costs can be measured in several ways including the direct costs incurred as a consequence of unexpected power failures, referred to as *Consumer Outage Costs.* However, outage costs are difficult to objectively measure for forward looking periods, though estimates of outage costs can be drawn from survey results. An alternative approach, referred to as *Capacity Costs*, determines reliability costs according to the incremental costs of generating capacity. In the presence of competitive wholesale markets, incremental capacity costs can be set equal to the observed market prices for generation capacity, as obtained from regional capacity auctions.

2.1.1 Marginal Energy Cost

Forward-looking estimates of marginal energy costs can be obtained in two ways, including *Internal Marginal Production Costs*, and *Market-Based Opportunity Costs*.

<u>*Internal Production Costs*</u>*:* An internal cost approach utilizes estimates of loads including hourly peak and off-peak demands along with primary fuel prices and parameters describing the individual units of the generation fleet such as installed capacity, maintenance schedules, and availability of generation units.[6] Least cost dispatch procedures are simulated, thus obtaining internal production costs over future timeframes.[7] In the case of energy-limited hydraulic power systems, marginal cost involves estimating the likelihood that incremental service to contemporary loads (next hour, day, or week) will impose higher costs on consumers in prospective periods.

<u>*Opportunity Costs*</u>*:* The alternative approach to cost estimation, opportunity cost, sets marginal energy cost according to the expected electricity prices, as estimated for wholesale electricity markets over forward periods. Generally speaking, electricity prices so determined are the result of competitive auction

losses) among the relevant locations. Essentially, a change in load at a specific location gives rise to changes in costs at multiple locations.

[6] The full set of parameters incorporated in power system simulations can include, for individual units, effective capacity, marginal heat rates, fuel costs, variable operations and maintenance costs (VOM), maintenance time, forced outage rates, time to repair, and ramp rates.

[7] For a simulation, the marginal energy cost in some hour of, say 2019, is the marginal running cost of the highest cost unit dispatched in order to satisfy the total system load in the hour.

procedures, and reflect the highest-valued use of the participating generator units, for the market as a whole. Properly designed, auctions obtain, simultaneously, least-cost short-run supply *and* set prices equal to the marginal cost of supply.

Under least-cost dispatch, internal production costs rise with increased demand. Competitive wholesale power markets present cost-minimizing opportunities not otherwise available: participating service providers and independent generators can maximize the value of their generation resources thus obtaining least total cost for the market as a whole. This result is obtained through 1) the sale of power under the condition when internal costs are less that than auction prices; and 2) the purchase of power from markets when internal costs are above auction prices. In the case of condition 1), it is appropriate to sell power up to the point where the internal marginal production cost approximates auction prices (*i.e.*, the market price). In the case of condition 2), it is appropriate to purchase power up to the point where the internal production cost savings approximates market prices.

In short, in the presence of competitive wholesale markets, the prices obtained reflect opportunity costs, the highest-valued use of marginal resources, such result is fully consistent with least cost dispatch. Generally speaking, an opportunity cost approach is the preferred methodology when service providers are actively engaged in competitive markets. As a practical matter, when applied over forward periods, the opportunity cost approach also involves dispatch simulation,[8] as applied to hourly loads and generation in the regional market. In this way, market prices are marginal costs – hence, the notion of opportunity costs.

Proposed Approach: The 2016 Marginal Cost Study of NLH will adopt the second approach, opportunity cost. For the forward year 2019, generation dispatch is simulated for the relevant regional markets, including those of the New York Independent System Operator (NYISO) and the Independent System Operator of New England (ISO NE). The result is estimates of hourly marginal energy prices, which are then compressed into average prices for the peak and off-peak commercial periods common to regional wholesale electricity markets of North America. Also, hourly marginal energy costs can be organized into peak and off-peak loads specific to the NLH system.[9]

[8] The simulation of forward-looking marginal energy costs is most applicable to thermal systems, and can involve modest-scale Monte Carlo simulation. The analysis procedures can include maintenance scheduling, 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 the current status as a matter of chronology. For units which are committed, each model iteration represents a different forced outage realization for the various units individually, leading to different sets of generators and reserve levels across hours. The set of available generators is then ordered into a supply function according to running costs (fuel and VOM). Marginal energy cost – measured at the generator bus bar – is equal to the intersection of the estimated level of demand and the supply function. Note that the simulation of wholesale market prices of generation is similar to the simulation of internal production costs.

[9] The relevant marginal cost of energy is internal NLH, under the condition of flow constraints along the transmissions paths to Northeast markets.

2.1.2 Marginal Reliability Cost

Marginal reliability cost refers to the change in the likelihood of power outage and the associated costs incurred by consumers, as a consequence of a change in load. Outage costs rise with respect to increases in load level, and decline with respect to load decreases. As mentioned above, reliability costs can be measured in three ways including *Consumer Outage Costs*, *Incremental Cost of Capacity* internal to the service provider, and *Capacity Auction Prices* in the presence of competitive wholesale markets for unbundled services. Marginal capacity cost refers to the annual charges related to the installation of capacity. Capacity cost is essentially the shadow price of consumer outage costs, providing that generation supply reasonably approximates least total cost. Marginal generation costs are of course load-related costs.

Consumer Outage Costs: Outage cost refers to the value or economic worth foregone by consumers as a consequence of not having electricity service available on demand.[10] Marginal outage cost is measured as $/kWh not served. Annual outage cost can be measured as the product of two metrics: the *Expected Unserved Energy* (EUE) or *Loss of Load Hours* (LOLH), and the costs incurred during power outages, referred to as *Value of Lost Load* (VOLL). In the context of hourly frequency, consumer outage cost is often measured as the product of the likelihood of an outage event, typically measured as *Loss of Load Probability* (LOLP) and *Loss of Load Expectation* (LOLE); and VOLL. Generally speaking, EUE is the preferred outage cost metric for purposes of cost estimation, insofar as the frequency, duration, and depth of power outages (MWs) are implicitly captured.

Internal Capacity Costs: Marginal capacity cost refers to the costs associated with incremental changes in expected peak demands. Marginal capacity cost is measured as $/kW-year; charges associated with marginal generating capacity are distributed to those hours in an annual period where reliability standards are not fully satisfied on an expected value basis. Power systems consist of large, highly-specialized facilities and equipment, implemented on a large scale. Because of the sheer scale of the investment, substantial planning and analysis underscore resource decisions. Properly executed, resource decisions are driven by least cost principles: expand total capacity up to the point where, over forward years, the

[10] This definition advances a comparatively narrow interpretation of generation reliability, where the level of realized reliability is measured with respect to load level – essentially, realized reliability is a function of total capacity installed with reference to peak demands. However, reliability can be viewed more broadly to include:

- committed units are capable of satisfying operating reserve requirements – total generation matches real time load changes (ramp speed);
- sufficient network observability such that system operators understand the status of the power system in real time;
- satisfaction of real-time operating parameters, such that supply-side events do not precipitate transient oscillations that challenge system-wide stability limits; and,
- realized voltages that remain within acceptable operating limits, both during peak and off-peak timeframes.

It is useful to mention that, historically, the observed breach of reliability often takes place during timeframes of comparatively modest load levels.

decline in expected outage costs incurred by consumers is just enough to offset the increase in total resource costs. In essence, the notion of least cost planning is an inherently marginal cost concept

Decisions to commit resources are based on expectations of the demand for and cost of capacity, *ex ante*. Necessarily, resource commitments are made in advance, and involve considerable risk with respect to electricity demand and, to a lesser extent, capacity costs. As with all decisions regarding costs and benefits in the future, resource decisions by electricity service providers are subject to forecast error. For generation capacity, resource commitment may take place several years prior to installation. At the time of installation and availability to provide power, demand levels – driven by regional economic activity and weather – may prove to be higher or lower than expectations at the time of commitment. As a consequence, realized outage costs of consumers, and the value of incremental capacity to arrest power outages, may deviate substantially from expectations implicit to expansion plans – for both the current period and near-term years following the installation (or acquisition) of new capacity.[11]

Capacity Auction Prices: This third alternative approach to reliability costs draws upon, where available, capacity auction prices as the basis for marginal capacity costs. The use of capacity prices obtained from competitive auction processes is a conceptually plausible basis to determine the economic worth of capacity insofar as both the New York ISO and ISO New England have organized capacity auctions. As a practical matter, the use of auction prices as the basis for generation capacity costs involves two dimensions: 1) accounting for line losses and, 2) ensuring that transmission capacity is in fact available to import reserve power along the two relevant transmission paths through Quebec and Nova Scotia-New Brunswick for markets of the New York ISO and ISO New England, respectively.

Proposed Reliability Cost Approach: Marginal reliability costs of the NLH 2016 Marginal Cost Study will utilize an internal cost approach, where capacity costs are set according to the internal costs incurred by NLH to provide incremental capacity. Annual capacity costs ($/kW-year) can be distributed to hours according to the approximate distribution of reliability costs across hours. As mentioned, capacity costs are essentially the shadow prices of consumer outage costs, providing that generation supply reasonably approximates least total cost. In our view, this approach is most relevant for the purposes at hand: cost allocation process and tariff design – tariff prices that remain largely unchanged over an annual period.[12]

Marginal generation capacity costs are, of course, exclusively load-related costs and, generally, are vanishingly small at off-peak load levels *on an expected value basis*: a change in load level has no

[11] Recent history chronicles several timeframes with supply-demand imbalance, including the comparative capacity-short position of the Eastern Interconnection during 1997-2001, California during 2002-2003, ERCOT during 2011-2015, and New England since 2004; and the comparative capacity-long position of the overall Eastern Interconnection for 2009 forward. Energy prices, scarcity rents, and capacity prices follow accordingly, with observed short-term wholesale prices reaching exceptional levels (*e.g.*, >$700/MWh) in capacity-short conditions.

[12] Dynamic, short-run marginal cost pricing of electricity, where the marginal prices facing consumers change frequently – *e.g.*, hourly real time pricing, critical peak pricing – take account of short-term changes in supply-demand balance, as a consequence of weather, generator unit outages, and other random events.

measurable impact on the capability of the system to satisfy total loads. However, changes in load levels, either load increases or decreases, can have a pronounced impact on realized reliability under unexpected circumstances. Even at modest load levels, changes in system conditions – *e.g.*, loss of large generator units, or unexpectedly high levels of load during off-peak seasons – can give rise to reliability concerns. At the end of the day, load-related reliability is a matter of available supply with reference to load level, regardless of whether the loads as a matter of magnitude are peak or off-peak. But certainly under expected value conditions, for both load level and available supply, reliability costs with respect to loads are concentrated during peak load timeframes.

Under the condition of complete foresight and knowledge regarding the future need for capacity and the costs of resources, and where resource indivisibility is not present, optimal least cost planning yields marginal capacity costs which approximate marginal outage costs. However, resource indivisibility is often present, insofar as the process of sizing facilities often favors, during the process of construction, oversizing beyond that which is needed during the early years of capacity life, as doing so reduces total facility costs in the long run – over extended future years. Other considerations often weigh on resource decisions and may, appropriately, influence the issue of least cost and, thus, estimates of marginal costs.[13]

It is useful to mention that, in lieu of internal capacity costs, estimates of capacity auction prices for 2019 could seemingly be utilized as the measure of reliability costs, but for practical considerations in the form of delivery constraints: the NLH system is not contiguous to the footprint of the regional wholesale markets with organized capacity auctions. Largely for this reason, the approach options available to the immediate study are limited to internal capacity costs though outage costs could also be estimated through simulation.

2.2 TRANSMISSION SERVICES

Introduction: Marginal costs of transmission services, like those of generation, include energy and reliability cost elements, with reliability costs expressed in terms of the outage cost-capacity cost paradigm. Unlike generation, marginal energy costs for transmission are in the form of network congestion and losses.

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[13] The concerns and views of regulatory authorities and interested stakeholders may favor certain resource choices, when compared to the resource set determined with even the most sophisticated analytical tools. As an example, strong social externalities may surface with respect to the announced siting of new generation in some locales.

Finally, risks associated with potential outcomes matter considerably; resource choices that obtain somewhat higher total costs, stated on an expected value basis, may be preferred to alternative lower cost choices, providing that the dimensions of risks are lower. Moreover, risks may be highly asymmetric and laced with low probability-high cost events. To the degree that these events are uncertain and not easily observably within historical experience, it is appropriate for resource decisions to be founded on 1) model results obtained from well-grounded analytical methods, as well as 2) informed intuition and *ad hoc* analysis and peripheral studies where relevant. In short, resource decisions need not necessarily be driven exclusively by the formal analysis implicit to generation planning tools and methods.

As described earlier, transmission services refer to the capability to transport energy from the locations where it is produced – generator sites – to locations where it is consumed – load centers. Generally speaking, generator locations can be described as *points of injection* of electricity into the transmission network; similarly, consumer locations, referred to as delivery points, can be described as *points of withdrawal* of electricity from the network. Transmission facilities can assume both radial and parallel path configurations; parallel paths can be in the form of either loop or meshed networks.

<u>*Marginal Transmission Cost, A Definition*</u>*:* The short-run marginal costs of transmission networks consists of energy costs, congestion, and reliability and are specific to time and location. Power systems are dominated by strong network externalities: a change in load (increase or decrease) at a specific location will have impacts on the total costs of serving all locations within the network. Furthermore, the locational cost impacts are specific to timeframe (hour, day, or year). Most remarkably, the marginal cost of transmission is unique to each location. This result, location-specific marginal costs, is a consequence of the physical properties of power systems.

Similar to generation, transmission service providers operate transmission networks in a manner that satisfies established reliability criteria – reliability standards identified by the North American Electric Reliability Corporation and adopted by regional regulatory authorities. Reliability standards are expressed in terms contingency survival and transient stability. Studies gauge the capability of networks to satisfy standards under expected future states of the network, which include expected peak load conditions. The proper expansion of transmission network increases the capability of the network at least cost, given that reliability standards are satisfied. Network expansion can also involve – *i.e.*, can be driven by – the expansion of generation including, as in the case of NLH, a major reconfiguration of power supply. Transmission investment costs complementary to generation are not on the margin with respect to changes expected peak loads and, arguably, should be excluded from marginal costs.

Transmission capability, in contemporary timeframes, is determined predominantly by loads and the spatial configuration of load centers and generation sites. Transmission capacity is expanded in order to satisfy expected peak loads, to reduce line losses, and to mitigate congestion, prospectively. In the case of line losses and congestion, the capability of the network will be expanded up to the point that the decrease in total energy costs associated with a decline in line losses and congestion approximates the incremental costs of expanding the network. In this context, the marginal capacity cost of transmission is the shadow price of reliability, and of energy in the form of line losses and congestion.

In principle, marginal transmission capacity cost is similar to generation as a matter of approach options. Accordingly, marginal capacity costs of transmission can be approached directly through simulation: estimating the impacts associated with the change in loads, including reliability, line loss, and congestion cost effects. Alternatively, marginal transmission costs can be measured in terms of shadow prices, a marginal capacity cost metric.

<u>Proposed Study Approach</u>: The immediate study assumes a capacity cost approach, for determination of peak-load related marginal transmission costs of the NLH system. For the prospective years 2018-2023, marginal transmission costs, stated on $/kW-year basis, are estimated from NLH's transmission expansion plans, and expected peak loads. For the defined period, the marginal transmission capacity cost is equal to the incremental investment costs (stated in 2019 $CAD) associated with peak loads, with respect to projected increases in peak loads.

3.0 SUMMARY OF PROPOSED METHODS

To summarize, the Company's 2016 Marginal Cost study will be based on the following proposed methodology:

3.1 Marginal Costs of Generation Services

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

<u>Reliability Cost set according to Internal Capacity Costs of NLH</u>: Reliability costs are based on the incremental capacity costs of an oil-fired combustion turbine generator, situated on a greenfield site near NLH load centers.

3.2 Marginal Costs of Transmission Services

<u>Energy Costs (Losses) Estimated through Simulation Studies</u>: Marginal line losses for transmission services will be estimated from a set of load flow studies. Load flow studies will reflect expected loads and the configuration of the NLH transmission system in 2019.

<u>Reliability Costs Based on Capacity Costs</u>: 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.

4.0 OBSERVATIONS, OUSTANDING ISSUES

Determination of marginal costs necessarily involves a fairly detailed understanding of the underlying power system and market context, at the outset. Our review of the Company's system and markets served reveals highly unusual features which, together, give rise to key challenges for cost estimation. First, the NLH system consists of integrated and isolated systems, where the isolated systems (diesel-powered systems) are likely to have markedly higher average costs. Second, the interconnected system is characterized by very low levels of load density; in addition, generation resources are separated from load centers by long distances. Third, NLH is putting in place a major reconfiguration of its generation and transmission resources – a transformation, literally. The end result: the selection of method(s) for marginal cost estimation must be approached cautiously, paying close attention to how intermediate studies (load flows, capacity cost estimates) are conducted. We harbor several concerns, highlighted by key observations as follows:

- *Energy Valued According to Opportunity Cost:* As discussed, opportunity cost is an appropriate basis for determining the economic value of energy, where service providers participate in formal auction-based markets for energy and reserves. This is the case for the Nalcor system beginning in 2019; as a consequence, the immediate marginal cost study utilizes estimates of market prices for this forward year ('19). Estimates of forward prices implicitly contain a substantial level of uncertainty in the form of energy price risk.
- *Line Losses (Transmission Energy Costs) Based on Load Flow Results:* Energy losses are unusually high, and marginal losses are higher still, because of key properties of the NLH power system including long lines and sparse load concentration. Marginal losses averaged across delivery points will, most likely, significantly differentiate all-in marginal costs according to season and between peak and off-peak timeframe. Marginal losses can vary dramatically with respect to system configuration and the location of the marginal generation (Labrador or Island).
- *G&T Capacity Costs:* For modest-sized power systems such as NLH, physical capital – particularly transmission – is often installed in sizable increments and thus characterized by high levels of indivisibility. As a result, the short-run cost impact arising from modest changes in load level (*e.g.*, < 5.0 MW) cannot be directly associated with incremental capacity. The proposed methodology, referred to as forward-looking short-run marginal costs, can be interpreted as an estimate of the average of the incremental costs that are likely to be incurred over several years, with respect to a change in load. The proposed method has inherent long-run cost elements. At issue is how best to attribute marginal capacity costs to hourly loads.
- *Labrador and Island Loads:* year 2019 is assumed to be the first full year of integration of NLH's Labrador and Island power systems. While the proposed study will provide a load-weighted average of marginal costs for the integrated system, the incremental costs to serve the Labrador loads will likely be much different from the Island loads during some timeframes.