NEWFOUNDLAND BOARD OF PUBLIC UTILITIES
DATA RESPONSES
TO
THE CONSUMER ADVOCATE

CA181 Provide a copy of the report to the Board concerning Newfoundland Power Company's Study of Innovative Approaches to Rate Design Based on Marginal Costs and Time-of-Use Design Principles (Page 4 of Wilson Pre-filed Evidence, lines 14-17).

RESPONSE:

A copy of the Report is attached.

CA182 On page 9 of his Pre-filed Evidence, Dr. Wilson states "If the Board chooses to implement rate design principles that reflect costs, consideration should be given to eliminating the RSP component that intentionally defers cost recovery to future time periods." Is Dr. Wilson recommending that the Board implement rate design principles that reflect costs? If not, what rate design principles is he recommending to the Board?

RESPONSE:

Yes. Dr. Wilson is recommending that the Board implement rate design principles that reflect costs.

CA183 In the absence of load research data, how should Hydro go about allocating distribution demand costs on the basis of non-coincident demand?

RESPONSE:

To the extent that available data does not lend itself to the estimation of distribution non-coincident demand, approximate allocators could be developed based on the experience of other utilities, or allocations could be done on the basis of energy consumption until Hydro is able to provide NCP estimates.

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NP-299 At page 19, Dr. Wilson discusses Hydro's lack of a seasonal rate, and states, "In short, in order for Hydro's rates to reasonably reflect costs, seasonal cost variations should be reflected. Conversely, if it is argued that the dominance of stored hydro generation overrides justification of seasonal rate differentials, then the attribution of hydroelectric capacity costs to demand and the allocation of these costs based on winter peak is inappropriate." Does Dr. Wilson have an opinion as to which of these two is the case, and if not, what is required for the Board to reach an informed opinion on it in this case?

RESPONSE:

It is Dr. Wilson's opinion that Hydro's rates should reflect seasonal cost variations. Even though the predominance of stored hydroelectric capacity in the generating mix may justify a smaller summer-winter rate differential than would be warranted on another system with correspondingly diverse seasonal load curves, the fact that Hydro allocates all generation demand costs on the basis of winter peak would warrant a significant winter rate premium.

NP-300 At page 21, Dr. Wilson discusses the lack of a demand rate to Newfoundland Power and states, "It would be far better, and a more reasonable regulatory procedure, to calibrate Hydro's costs and wholesale rate structure in this proceeding so that retail rate design in the next NP case can reflect the appropriate cost-based charges that NP will actually realize as its retail sales volume changes." Since a large share of Newfoundland Power's customers are served at non-demand rates themselves, why would having Newfoundland Power pay a demand charge link the revenues that Newfoundland Power receives from these customers more closely to the charges Newfoundland Power sees as the load changes?

RESPONSE:

Wholesale rates that separately reflect demand and energy costs as well as seasonal and time-of-use cost differences would enhance NP's ability to improve retail cost allocation as well as rate design. While it may continue to be cost prohibitive to implement time-of-use or three part rates for small customers, class cost allocations may be improved, and there will be greater flexibility to experiment with and improve retail rate design over time if the underlying costs are more accurately differentiated.

NP-301 In Dr. Wilson's opinion, are the costs of serving the demands of Newfoundland Power reflected in Hydro's cost of service study that is used to directly derive the rate to Newfound Power?

RESPONSE:

The costs of serving the demands of NP, like all of Hydro's costs, are included in Hydro's cost of service study underlying its rates – and, to an extent, they are even reflected in the rates that Hydro charges. That said, there are, nevertheless, ways in which the linkage between Hydro's rates and cost incurrence can be improved and that may change the amount of Hydro's costs that are now attributed to NP.

NP-302 At page 22, Dr. Wilson states "rates which reflect marginal cost responsibility are more allocatively efficient and better embody the principles of fairness, equity and causal responsibility…." Why does Dr. Wilson think marginal cost-based rates are more fair than embedded cost-based rates, and does Dr. Wilson believe most of society shares that opinion?

RESPONSE:

A price equal to the marginal cost of a product requires buyers to pay a price equal to the cost incurred or saved by supplying one more or one less unit of the product. In this way sellers are not required to produce additional units that provide less benefit than they cost to produce; buyers are not encouraged to consume additional units that provide less benefit than they cost to produce; sellers will continue to produce additional units as long as the benefits derived from each additional unit exceed production costs; and buyers will not be denied additional consumption, the benefits of which exceed the cost of production. In addition, production resources will be allocated among products so as to maximize society's aggregate economic welfare (i.e., total benefits minus total costs). These fundamental principles are virtually unexceptional and universally accepted as the key underpinnings of allocative efficiency and economic welfare maximization.

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NLH-31 (Re: p. 9, Lines 6-9) Identify any circumstances which would have changed since 1985 regarding customer bill volatility. Outline how circumstances have changed which would warrant the elimination of the Rate Stabilization Plan at this time?

RESPONSE:

Customer bill volatility, absent the RSP, would be increased by such factors as fluctuating fuel prices, inflation, money costs, exchange rates, and variations in operating efficiency and use patterns.

Inflation and money cost volatility has generally been less in recent years than in the early 1980s and fuel prices, while certainly not stable, have also been somewhat less volatile and changes more predictable than in the late 1970s and early 1980s. If Hydro is now expected to act and perform as would a private sector utility, it should attempt to provide more timely and accurate price signals to all market participants.

NLH-32 Mr. Brockman states on p. 5 of his evidence that “The major issues of cost allocation were decided by this Board following the 1993 generic cost of service hearing. We should not now have to re-try most of them again anytime soon.” What is Dr. Wilson’s view of generic proceedings, rather than rate proceedings, as an appropriate forum for settling methodology issues?

RESPONSE:

Generic proceedings facilitate the development of principles that might be applied consistently over many companies. When only 1 or 2 companies are affected by the results, the principles could almost as easily be developed in individual rate proceedings that would facilitate any adjustment desired for each company. In this case, the referenced generic proceeding is fairly old, and, to the extent the Board determines that issues were either not fully and finally resolved there or that the old resolutions should no longer hold, modifications are entirely appropriate here.

NLH-33 (Re: p. 8, Lines 14-17) Identify the specific items that would be included in the "cost savings to a utility if a customer leaves the system." Is this method of identifying the customer costs of a distribution network typically used in other jurisdictions?

RESPONSE:

The cost savings to a utility, if a customer leaves the system, would include the variable costs (e.g., fuel costs, meter reading, billing, etc.) that the utility would avoid by not having to serve that customer. While not familiar with the methodology used by each jurisdiction where marginal cost principles are applied, it is generally recognized that the incremental costs of serving an additional load or the incremental cost savings of load reduction reflect marginal costs.

NLH-34 (Re: p. 7, lines 4-8) To what extent does the timing of the peak and the allocation method for demand costs influence the need for seasonal rates? Is it Dr. Wilson's recommendation that the seasonally differentiated rates be based on marginal or embedded costs?

RESPONSE:

The need for seasonal rates is driven by the extent to which demand and costs vary by season, not by the timing of the peak or the demand cost allocation method. Seasonally differentiated rates should reflect marginal costs and the embedded cost revenue requirement.

NLH-35 (Re: p. 8, lines 6-9) What is the cost driver, for example, peak demand or energy throughput, that is the determinant of investment in a transmission system? If the above answer is energy or a combination of energy and demand, how does a change in energy throughput that does not change peak demand, cause a change in transmission design?

RESPONSE:

Both peak demand and energy requirements determine transmission investment requirements. While peak demand obviously affects capacity requirements, that is not fully determinative of costs. Other factors, such as the type and location of generation facilities, which are greatly influenced by energy requirements, also influence the design and costs of the transmission system.

NLH-36 To what extent is the sizing of a transmission line related to the magnitude of the load to be served versus the hours of use of the load to be served?

RESPONSE:

The capacity of a line is related to “magnitude of load.” The size of a transmission system and the required investment in it are substantially influenced by hours of use. Large and expensive transmission grids (like costly baseload generating units) are economically justified by the extent of their use – not just peak demand.

NLH-37 Related to classifying transmission costs:

(a) Is it true that the Federal Energy Regulatory Commission (FERC) regulates transmission pricing in the U.S.?

(b) Is it true that the so-called FERC pro-forma transmission rates called for in FERC Order 888 is universally used in the U.S., so long as there are no constraints, is calculated by dividing the total annual cost of transmission by the single coincident peak demand for point-to-point transmission service, and by either the single coincident peak, or the average of the twelve monthly coincident peaks for network transmission service?

RESPONSE:

(a) The Federal Energy Regulatory Commission ("FERC") regulates wholesale transmission pricing; that is, rates for wheeling service and the transmission component of wholesale service. State regulatory commissions regulate all retail rates, including the recovery of all transmission costs and wholesale transmission charges. Thus, transmission cost price signals to ultimate consumers reflect, primarily, cost allocation procedures adopted by state commissions, which frequently adopt cost allocation procedures and rate design concepts that attribute some transmission costs to energy rather than demand.

(b) This has generally been the case only for that portion of transmission costs allocated to wholesale transactions. Historically, most transmission costs in the U.S. have not involved wholesale sales. In any event, as indicated in the response to part (a) of this question, both FERC transmission costs and transmission costs attributed directly to retail jurisdictions, are ultimately reflected and dealt with in retail cost of service studies and rate designs at the State jurisdictional level.

NLH-38 Please provide the names of any U.S. and Canadian utilities that allocate transmission costs based on energy.

RESPONSE:

Dr. Wilson has not undertaken the requested survey.

NLH-39 (Re: p. 8, lines 10-17)

(a) Is the size of a distribution substation used to transform voltage from transmission level to distribution primary voltage level determined on the basis of its total peak demand served? If not, how is it sized and what determines when it is fully loaded and requires reinforcement?

(b) What would determine the total peak demand of the aforementioned substation, the coincident peak demand of the various rate classes served by the substation or the sum of the non-coincident demands of the various rate classes? If the answer is the non-coincident peak demand, how does that sum, which is higher than the coincident peak demand, increase the load carrying burden of the transformer?

RESPONSE:

(a) See response to NLH-36, above. The capacity of any given substation will be a function of its peak load (i.e., a component of the utility's NCP), not the peak coincident load of the utility.

(b) The coincident peak demands of various distribution substations are likely to be non-coincident with the coincident peak demand of the entire utility.

NLH-40 (Re: p. 8, lines 10-17) Is it necessary for the distribution system to peak at the same time as the total system in order for the coincident peak demand method to be used with the local distribution system?

RESPONSE:

For a utility that sells all of its output at the distribution level, the system coincident peak and the distribution sales coincident peak are the same. However, local area peaks are not likely to be uniformly coincident with the system peak, and the sum of these NCPs will exceed the system CP. While any method can be used, some provide better price/cost signals than others. In the case of local distribution demand costs, a system coincident peak allocator is generally not thought to be the best approach.

NLH-41 (Re: Dr. Wilson's Report, p. 18) It is asserted that rate class contributions to those local loads are not generally measured with precision, and therefore some available proxy must be used. It is then recommended that the non-coincident peak method be used for that purpose. If rate class load research can identify the hour of the rate class non-coincident peak demand, should it not, with the same accuracy, be able to identify the rate class contribution to the coincident peak of distribution substations and primary circuits?

RESPONSE:

It may. However, since the capacity costs of these facilities are not determined by the system coincident peak, such an identification may not be very helpful to cost allocation and rate design question.

NLH-42 (a) Define the following terms:

- Incremental cost
- Short-run marginal cost
- Long-run marginal cost
- Long run incremental cost

(b) How is each calculated for an integrated electric utility?

(c) How should each of these costs be reflected in rate design?

RESPONSE:

(a) Definitions:

- Long Run Incremental Cost (LRIC) – The change in total costs when output is increased or decreased by an increment or block of output for a period of time during which system capacity can be altered.

- Short Run Incremental Cost (SRIC) – The change in variable costs when output is increased or decreased by an increment or block of output for a period of time during which system capacity cannot be altered.

- Long Run Marginal Cost (LRMC) – The change in total costs when output is increased or decreased by one unit of output for a period of time during which system capacity can be altered.

- Short Run Marginal Cost (SRMC) – The change in variable costs when output is increased or decreased by one unit of output for a period of time during which system capacity cannot be altered.

(b) Long Run and Short Run Marginal costs are usually calculated as the first derivative of the total cost and total variable cost functions, respectively. Corresponding incremental cost values can be calculated as the difference in total or variable costs with the addition of an increment or block of output.

(c) Marginal or incremental costs can be used to develop a variety of rates, e.g., seasonal rates, time of day rates, interruptible rates, rates for off-peak service, etc. For greater elaboration see Bonbright, et al., <u>Principles of Public Utility Rates</u>, Public Utility Reports, Inc,: Arlington, Virginia, 1988; and Alfred E. Kahn, <u>The Economics of Regulation: Principles and Institutions</u>, John Wiley & Sons, Inc.: New York, 1970 (Volume 1) and 1971 (Volume II).

NLH-43 What rate structure would be appropriate for a situation where the average energy cost is 3¢/kWh, the incremental fuel cost is 5¢/kWh, the average demand cost is 10¢/kW/month and the class load factor is 60%?

RESPONSE:

Dr. Wilson cannot provide an answer from the information given.

NLH-44 Based on your knowledge of TOU rates that have been implemented in other jurisdictions, what level of relative peak to off-peak costs are necessary for customers to change their usage patterns by a significant amount leading to a positive impact on the utility's expansion plan costs?

RESPONSE:

Price elasticity of demand varies substantially between types of customers and electricity uses. For many uses, a price differential of 10% to 20% may have an equivalent impact (i.e., 10% to 20%) on demand, other things equal. Cost reflective rates, such as TOU rates, are justified both by equity and allocative efficiency considerations.

NLH-45 How does the existence of the RSP affect the implementation of marginal cost based rates?

RESPONSE:

The RSP involves the deferral of recovery (from ratepayers) of costs incurred at one time period and the recovery of those costs in a subsequent period, thus, potentially distorting marginal cost price signals.

NLH-46 (Re: Dr. Wilson's Report, p. 27, graph) Do you agree that the horizontal axis of the figure of your Report represents the unit size of equipment, i.e., for distribution transformers, the kVA rating? Do you agree the vertical axis of the figure on p. 27 of your Report represents the unit cost of the equipment, i.e., for distribution transformers, the installed cost for each size transformer?

RESPONSE:

Yes.

NLH-47 (Re: Dr. Wilson's Report, p. 27) A statement is made that "there would still be no valid basis to attribute all of the difference between actual cost and zero load cost entirely to coincident peak demand and none of these costs to energy." What would be the rationale for treating any of the cost of distribution as energy related?

RESPONSE:

Usage expectations and requirements influence equipment design and cost. Equipment that must operate continuously and reliably 24 hours a day, 365 days a year has design specifications and costs that exceed what might be required to operate for only a single hour.

NLH-48 (Re: Dr. Wilson's Report, pp. 28, 29) You point out that 5 apartment buildings each with 40 individually metered apartments would have essentially the same distribution system as 4 office buildings with overall identical peak loads. Would 200 single family homes with an average lot width of 30 meters have the same distribution system as 100 single family homes with an average lot width of 30 meters? What if the 200 and 100 homes were rural residences of the type served by Hydro?

RESPONSE:

Less densely developed market areas typically require more conduit and transformers per customer, other things equal.

NLH-49 (Re: Dr. Wilson's Report, p. 30) What other clearly identifiable distribution costs besides "accounting and billing, meters, and service line drops" should be classified as customer related costs? Will the inclusion of only costs associated with accounting and billing, meters, and service line drops tend to understate the level of customer related costs? Are there distribution costs that are not directly related to demand, energy or customer fluctuations?

RESPONSE:

Another customer-related cost is the cost of meter reading. Including only the costs of customer specific facilities (e.g., meters) and customer specific functions (e.g., meter reading) in the customer cost classification does not tend to understate the level of customer related costs. Moreover, given the near-zero impact that customer charge variations have on consumer choice, the importance of precisely accurate price signals in the customer charge is less important from an allocative efficiency perspective than the accuracy of other cost-reflective price signals; e.g., those for demand and energy.

Some costs such as the additional cost of undergrounding facilities may be viewed as not "directly related" to demand, energy, or customer fluctuations.

NLH-50 Does the use of incremental fuel cost for the energy portion of the industrial non-firm rate reflect short run marginal pricing?

RESPONSE:

Yes. However, these customers have no unique “right” to short-run marginal cost prices while others do not. The failure to attribute base-load generation plant capital costs to them means that others must subsidize their consumption. This is especially inequitable to the extent that base-load generation plant costs serve to reduce short run marginal costs.

NLH-51 (Re: Dr. Wilson's Report, p. 38) If "the generators that use this fuel exist for peaking purposes," why is it appropriate to classify this fuel expense to energy rather than demand?

RESPONSE:

The fuel is used and its cost is incurred only when the plants operate to produce energy – in precisely the same manner as the use of fuel for other generating facilities.

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IC 274. With reference to J.W. Wilson's evidence on page 36 and 37, where he states "assuming the same energy charge for interruptible usage as for firm industrial (2.309 cents/kwh), an interruptible customer with a 50% load factor would pay 2.72 cents per kWh (the price with an 80% load factor would be 2.56 cents) versus 4.80 cents per kWh for firm service to NP (or 4.23 cents per kWh for a firm industrial with a 50% load factor.).:

a. For the assumed energy rate of 2.309 cents per kWh, what would be the necessary price for No. 6 fuel ($C/barrel) in order for this assumption to be true?

b. Redo the calculation for 50% and 80% load factor based on the cost of service price of $28 per barrel for No. 6 fuel.

RESPONSE:

a. No particular oil price was assumed. The only assumptions in this hypothetical were (1) a 50% load factor, and (2) an interruptible energy rate equal to the firm energy rate (2.309¢ per kWh).

Using the Industrial Non-Firm tariff formula as provided in the filing Schedule A at page 3 of 27:

> "Non-Firm Energy is deemed to be supplied from thermal sources. The following shall apply to calculate the Non-Firm Energy rate:
>
> $$\{(A \div B) \times (1 + C)\} \times 100$$
>
> A= the monthly average cost of fuel per barrel for the energy source in the current month or, in the month the source was last used
>
> B= the conversion factor for the source used (kWh/bbl)
>
> C= the administrative and variable operating and maintenance charge (10%)
>
> The energy sources and associated conversion factors are:
>
> 1. Holyrood, using No. 6 fuel with a conversion factor of 610 kWh/bbl
> 2. Gas turbines using No. 2 fuel with a conversion factor of 475 kWh/bbl
> 3. Diesels using No. 2 fuel with a conversion factor of 556 kWh/bbl."

Thus, applying this formula yields:

$$(A \div 610) \times 1.1 \times 100 = 2.309 \text{ cents}$$

$$110A = 2.309 \times 610$$

$$A = \$12.80445$$

b. Dr. Wilson has made no calculations of energy rates based on oil prices. He does agree that cost reflective energy rates (both firm and interruptible) should be expected to be higher with high oil prices than with low oil prices. They would also be higher with low fuel conversion efficiency (kWh per barrel) than with high efficiency.

By using the tariff formula described above:

$$(28 \div 610) \times 110 = 5.049 \text{ cents per kWh}$$

With a 50% load factor, the demand charge is .411 cents per kWh, so the cost would be 5.46 cents per kWh.

With an 80% load factor, the cost would be 5.306 cents per kWh.

IC 275. COS – Classify hydraulic storage Reference: John Wilson at p 12.

Please clarify the basis for assuming that hydroelectric plants are built only to meet the “base load”. Comment on the situations in Canada where storage facilities are utilized to ensure that water is made available when it can best serve winter peak system needs. Contrast this with run-of-river hydro facilities in Canada where no storage is available and river peak flows do not match system load peaks. If storage is used to meet system peak needs as well as to supply energy (by ensuring it is not spilled), confirm that the classification should reflect both functions – and explain how you would see this best being done under the examples noted here.

RESPONSE:

The term “base load,” as used in this statement refers to loads that are relatively stable over an extended time period, encompassing both peak and offpeak usage periods. Thus, base loads do contribute to peak loads, and all loads that occur at peak times should be charged equivalent peak period cost levels.

Capital intensive plants with relatively low running costs, such as storage hydro, are efficient construction choices if they can be run enough hours (i.e., “base load”) so that the money saved by virtue of their low running cost is enough to pay for their higher capital costs.

For ratemaking purposes, the portion of capital costs attributable to peak “demand” (as opposed to energy) should generally be limited to the capital cost of the least costly (to build) type of facility. Capital costs in excess of that amount are logically incurred in order to achieve running cost savings. Therefore, as a general proposition, more capital intensive generating plants (i.e., those with higher construction costs per kW of capacity) should have a larger percentage of their capital costs attributed to energy. Conversely, plants that are cheap to build will have a larger percentage of their capital costs attributed to demand.

Other things equal, run-of-river hydro capital costs are generally less than storage hydro capital costs. As stated on page 13 of his Report, Dr. Wilson agrees that storage hydro capacity that is used to meet both peak capacity and system energy needs should have a portion of its costs classified energy-related and a portion classified as demand-related. As a general rule, the portion classified as demand should not exceed the cost of the lowest cost capacity that could be built, and the balance should be classified as energy.