IEc

BEFORE THE RÉGIE DE L'ÉNERGIE

IN THE MATTER OF:

HYDRO QUÉBEC TRANSÉNERGIE

Demande du Transporteur relative à la politique d'ajouts au réseau de transport

DOSSIER R-3888-2014

5 December 2014

prepared on behalf of:

l'Association québécoise des consommateurs industriels d'électricité (AQCIE)

Conseil de l'industrie forestière du Québec (CIFQ)

prepared evidence of:

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1. INTRODUCTION

PLEASE STATE YOUR NAME AND BRIEFLY DESCRIBE YOUR BACKGROUND.

My name is Robert D. Knecht. I am a Principal of Industrial Economics Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. As part of my consulting practice, I prepare analyses and expert evidence in the field of regulatory economics. In Canada, I have submitted expert evidence in regulatory proceedings in Québec, Ontario, Alberta, New Brunswick, Nova Scotia, Manitoba, and Prince Edward Island. In Québec, I have submitted evidence in proceedings involving Hydro Québec TransÉnergie, Hydro Québec Distribution, and Gaz Métropolitain, in matters involving utility revenue requirements, cost allocation, cross-subsidization, rate design, and industry restructuring. My résumé and a listing of proceedings in which I have submitted expert testimony in the past five years is attached as Exhibit IEc-1.

WHAT IS THE PURPOSE OF THIS TESTIMONY?

L'Association québécoise des consommateurs industriels d'électricité ("AQCIE") and Conseil de l'industrie forestière du Québec ("CIFQ") requested that I review the filing and interrogatory responses of Hydro Québec TransÉnergie ("HQT" or "the Company") in this proceeding, and evaluate whether the proposed system expansion cost and customer contribution policies comport with sound economics and regulatory principles.

WHY DO REGULATED UTILITIES EMPLOY CUSTOMER CONTRIBUTION POLICIES?

As a general rule, utilities establish posted rates that are designed to provide a reasonable opportunity for the utilities to recover their full book revenue requirement. In large part, the utility revenue requirement is based on historical average "embedded" costs, and includes operating costs, depreciation, and allowed return on historical rate base.[1] Thus, utility rates generally reflect the average embedded book cost of service.

When a new customer is added to the utility system, the incremental cost to serve that customer is likely to be different, and possibly very different, from the average embedded book costs which serve as the basis for the rates that the new customer will pay.

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[1] While some utilities perform cost allocation studies based on marginal costs, and some posted tariff rates reflect the marginal or incremental cost of providing service, overall utility rates are generally "trued up" to the overall average cost revenue requirement.

Conceptually, this mismatch between incremental costs and incremental revenues has implications for both economic efficiency and inter-customer equity (or fairness).

Regarding economic efficiency, in the case where the incremental revenues from a new customer exceed the incremental cost of service, setting the rates for the new customer at average cost may inefficiently discourage new customers from attaching to the network. In the case where the incremental cost of serving the new customer exceeds the rates that the new customer will pay, the traditional ratemaking approach may result in new customer attachments that are economically inefficient, in that the value of the service to the new customer may fall short of the incremental cost of providing that service.

From an equity standpoint, there is a tradeoff between existing customers and new customers. If rates exceed the incremental cost of providing service to a new customer, then existing customers benefit from the attachment of the new customer. Where rates fall short of the incremental cost of providing service to a new customer, then existing customers are asked to absorb the shortfall in revenues.

A summary of the economic efficiency and equity considerations is shown in Table IEc-1 below.

TABLE IEc-1
REGULATORY IMPLICATIONS FOR NEW CUSTOMER ATTACHMENTS

	Efficiency Implications	Equity Implications	Regulatory Response
Tariff Rates Exceed Incremental Cost	May preclude efficient attachments	Existing customers benefit from new customers.	"Flex" Rates, in certain well-defined circumstances
Incremental Cost Exceeds Tariff Rates	May result in inefficient attachments	Existing customers make up shortfall from new customers.	Customer contributions.

WHAT POLICIES DO REGULATORS EMPLOY FOR ADDRESSING THESE ISSUES?

In circumstances where tariff rates exceed the incremental cost of providing service, and where such policies actually prevent a customer attachment that would otherwise be efficient, regulators may adopt discounted or "flex" rates for specific customers, in which rates for specific customers are set below the regular posted tariff rates. (Flex rates are probably more common for distribution utilities than transmission utilities.) While such policies are more often applied to existing rather than new customers, there are a wide variety of "economic development" and other forms of flex rates that are used to both attract and retain customers.[2] This type of flex rate approach serves to mitigate economic efficiency problems, but existing customers generally continue to benefit from the attachment of new customers in these circumstances.

In circumstances where tariff rates fall short of the incremental cost of service, regulators generally adopt customer contribution or "maximum investment" policies. As a general rule, a customer contribution policy compares the present value of the incremental cost of providing service to present value of the rates that the new customer will pay. The required customer contribution equals the difference between those two values. Or, equivalently, the regulator will establish a maximum investment level that the utility will make in order to attach a new customer, which is equal to the present value of new revenues less incremental O&M costs. The customer is then required to make a contribution equal to the attachment costs in excess of the maximum allowed investment.

MS. CHANG REFERS TO FERC'S "HIGHER OF" POLICY. HOW DOES THIS CONCEPT FIT IN THIS FRAMEWORK?

FERC's "higher of" policy for new transmission customers is conceptually consistent with the customer contribution policies of many different kinds of utilities. In essence, it represents a balance between the principles of economic efficiency and equity.

From an economic efficiency standpoint, applying an incremental cost charge will serve to both attract all customer additions that are able to cover the incremental cost and discourage customer additions that cannot do so.

However, from an equity standpoint, the pure incremental cost approach is often seen as lacking. At any point in time, the existing customer base is paying the

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[2] Flex rates can create a variety of regulatory problems, and are therefore generally applied only cautiously. First, regulators generally require that any customer who is eligible for a discount flex rate must demonstrate that it has an economically viable alternative that it could pursue if the flex rates were not offered. Second, regulators take steps to ensure that the flex rates are not unduly discriminatory, in that they are not deemed to be unduly inequitable or result in inappropriate economic advantages for some customers at the expense of others. In general, flex rates are applied only when doing so results in a net benefit to other ratepayers, and when such rates are not unduly discriminatory.

total cost of the existing system. When a new customer is added to the system, it will likely benefit from at least some aspects of the existing infrastructure. If the new customer pays only the incremental cost of attaching to the system, this new customer makes no contribution to the existing infrastructure. Moreover, unless incremental costing is carefully structured, the new customer will not make any contribution to reliability or product quality upgrades. This approach is often seen as inequitable by regulators (and, of course, existing customers).

Thus, the "higher of" approach to regulatory policy represents a balance between the economic efficiency of incremental cost pricing and fairness considerations. It anticipates that there are a variety of new customers and projects. Some will pay embedded cost rates which exceed incremental cost, and thereby contribute to the fixed cost of the existing infrastructure. Some will pay incremental costs, and make little or no contribution to the existing infrastructure they use. Thus, as the name implies, the policy anticipates that new customers will be subject to *either* embedded cost or incremental cost charges, whichever is higher.

IS THE DEVELOPMENT OF A MAXIMUM INVESTMENT LEVEL A SIMPLE CALCULATION?

While the issue is conceptually straightforward, there are a number of significant issues that must be addressed as part of the calculation. In my experience, different utilities and different regulators take different approaches to these issues, based on their judgment and their assessment of the particular needs of the utility's service territory.

A partial list of these issues is as follows:

- What is the appropriate time period to use for utility recovery of incremental revenues?
- What incremental costs should be included in the cost calculation? In particular:
  - Should incremental costs include only those costs necessary to attach the customer to the system "backbone," or should incremental costs include "deep system" investments that are triggered by the new customer?
  - Should incremental costs include only those necessary to accommodate the new customer under the existing network configuration of generators and loads, or should incremental costs include the acceleration of system investments that would otherwise not be necessary for several years?

- As with all incremental cost calculations, the question of the "but for" scenario is critical. Thus, for evaluating the incremental cost to serve new customers, how is the cost scenario for the utility *without* the new customer defined? For example, does the "but for" scenario anticipate any system replacements that are planned for reasons other than load growth or new resources, or is it simply based on the existing grid as configured?
- How should O&M and capital taxes be factored into the calculations?
- What level of inflation, if any, should be assumed for tariff revenues related to the new customer?
- Should new customers be implicitly required to contribute to reliability and product quality upgrades in the development of the maximum investment level?
- How should discriminatory impacts in timing be reflected in the policy? For example, if the utility has excess capacity at the time one new customer requests service, the incremental cost to serve that customer may be very low. However, a second customer, with exactly the same load parameters, may trigger a much larger investment requirement. Strict implementation of the customer contribution policy may be deemed to cause undesirable rate discrimination.
- How are the impacts of multiple projects allocated among the new loads?
- To what extent should maximum levels be accumulated, such that excess maximum investment credits from one project may be used to offset shortfalls in other projects?
- What is the appropriate rate of return on capital used for deriving present value?

WHAT ARE THE SPECIFIC CONCERNS SURROUNDING THE CUSTOMER CONTRIBUTION POLICY THAT APPLY TO HQT IN THE CURRENT PROCEEDING?

As with all customer contribution policies, HQT faces the traditional concern of balancing the interests of new customers with those of existing customers. Thus, it is important that the customer contribution policy not provide an undue benefit to either new customers at the expense of existing customers or to existing customers at the expense of new customers.

Second, HQT has two basic classes of customers from whom it must recover its revenue requirement, who take service under very different tariffs. These are native load customers, who indirectly take transmission service through Hydro

Québec Distribution ("HQD") in HQT's "Native-Load Transmission Service" tariff.[3] In addition, there are point-to-point ("PTP") customers, who take service under the "Point-to-Point Transmission Service" tariff. The fundamental regulatory criterion of avoiding undue discrimination suggests that, in establishing a customer contribution policy, it is important to ensure that the policies which apply to native load service are comparable to those that apply to PTP service.[4] Similarly, it is important that customer contribution policies apply equally to all PTP customers.

An emphasis on equivalent treatment of all customers is particularly important given the integrated nature of Hydro Québec. Hydro Québec Production ("HQP") is the dominant customer. To state the obvious, HQP earns profits on the export of power, which are derived from market-based revenues in the export markets, less HQP's costs, less the charge from HQT to provide transmission service from the generator to the export market. Thus, HQP, and in fact all of Hydro Québec, have an economic incentive to increase transmission costs assigned to native load customers and to reduce costs assigned to PTP customers. Moreover, to the extent that HQP competes with other PTP customers in the export markets, it has an incentive to reduce costs assigned to HQP as a PTP customer and increase costs assigned to other PTP customers. The incremental cost nature of the customer contribution policy opens the possibility that HQP could take advantage of its integrated status (such as internal knowledge of the transmission system) to improve its competitive position either at the expense of native load customers or at the expense of other PTP customers.

I am not presenting evidence that Hydro Québec is in any way taking advantage of its position as monopoly supplier of transmission and distribution services with respect to enhancing its export profits. Nevertheless, the Company's economic incentives should be recognized in establishing a customer contribution policy.

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[3] If Hydro Québec had been fully unbundled, one would expect that the distributor would represent the interests of its native load ratepayers in this proceeding.

[4] In Québec, the Régie has generally been more rigorous in its enforcement of this principle, as it generally requires system expansion costs for both native load and PTP customers to meet the same test, based on the rationale of tariff neutrality. In many places, native load is not subject to a maximum investment limit or the "higher of" standard. See, for example, HQT-4, Document 5, FCEI IR-7.1 and Docket No. R-3738-2010, HQT-10, Document 5 page 17.

2. MAXIMUM INVESTMENT CALCULATION

HOW DOES HQT PROPOSE TO ESTABLISH THE MAXIMUM INVESTMENT LEVEL FOR NATIVE LOAD?

HQT's open access transmission tariff ("OATT") states that the maximum investment amount *"is calculated from the present value over twenty (20) years of the point-to-point rate . . . less 15% to account for the present value over twenty (20) years of operation and maintenance costs for Network Upgrades completed, as well as for the amount of the applicable tax and public utility tax."*[5]

Pursuant to this policy, HQT uses the $74.65 per kW PTP rate and calculates that this rate implies a maximum investment of $598 per kW. As a matter of arithmetic, however, this $598 per kW rate is simply not the present value over 20 years of $74.65 per kW, adjusted for O&M and property tax costs, at HQT's cost of capital.

HQT's supporting calculations are shown in Table 1 of Ms. Chang's evidence (HQT-2, Document 1), as well as in the Company's supplemental evidence at HQT-3, Document 1, Table 1. This methodology was apparently approved by the Régie in Decision 2002-95, and thus has been in place for a number of years.

What Ms. Chang's table shows is that the $74.65 per kW is the first-year utility revenue requirement associated with an HQT investment of $598 per kW. Under normal utility accounting, and as shown in Ms. Chang's table, the annual utility revenue requirement declines every year, while the revenues generated from the new customer are normally expected to remain the same or increase. Thus, revenues from the new customer at $74.65 per kW will exceed the utility revenue requirement associated with an investment of $598 per kW in every year except the first. For example, as shown in Ms. Chang's Table 1, the utility revenue requirement in 2020 for a $598 per kW investment is $63.50 per kW, whereas the customer will be providing $74.65 per kW even without an inflation adjustment.

I have prepared an alternative version of Ms. Chang's calculation, shown in Table IEc-2 below. As shown, if levelized revenues are assumed (and no other changes made), the maximum investment credit would be $740 per kW rather than the $598 per kW in the current method.

[5] HQT OATT at Attachment J, Section A. It is my understanding that the public utility tax has been repealed. HQT-3, Document 1, footnote 4.

TABLE IEc-2				
MAXIMUM ALLOWANCE UNDER 20-YEAR DEPRECIATION				
[a]	Investment ($/kW)	740	<=== Increase over HQT	23.7%
[b]	Return	5.666%		
[c]	PV O&M	15.00%		
[d]	Yearly O&M (%)	1.27%		
[e]	Yearly Tax Rate	0.55%		
[f]	Rate/O&M Inflation	0.00%		

Year	Depreci-ation	Rate Base	Cost of Capital	Sub-Total	O&M	Taxes	Revenue Requirement	Revenue	Revenue Less O&M/Taxes
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Start		740							
2014	37	703	42	79	9	4	92.36	**74.65**	61.17
2015	37	666	40	77	9	4	90.06	74.65	61.38
2016	37	629	38	75	9	4	87.76	74.65	61.58
2017	37	592	36	73	9	3	85.46	74.65	61.78
2018	37	555	34	70	9	3	83.16	74.65	61.99
2019	37	518	31	68	9	3	80.86	74.65	62.19
2020	37	481	29	66	9	3	78.57	74.65	62.39
2021	37	444	27	64	9	3	76.27	74.65	62.60
2022	37	407	25	62	9	2	73.97	74.65	62.80
2023	37	370	23	60	9	2	71.67	74.65	63.00
2024	37	333	21	58	9	2	69.37	74.65	63.21
2025	37	296	19	56	9	2	67.07	74.65	63.41
2026	37	259	17	54	9	2	64.77	74.65	63.61
2027	37	222	15	52	9	1	62.48	74.65	63.82
2028	37	185	13	50	9	1	60.18	74.65	64.02
2029	37	148	10	47	9	1	57.88	74.65	64.22
2030	37	111	8	45	9	1	55.58	74.65	64.43
2031	37	74	6	43	9	1	53.28	74.65	64.63
2032	37	37	4	41	9	0	50.98	74.65	64.83
2033	37	0	2	39	9	0	48.69	74.65	65.04
Present Value				**740**	**111**	**29**	**880**	**880**	**740**
			O&M and Tax Percentages ==>		**15.0%**	**4.0%**			

Sources & Notes:

[a]: Derived iteratively from present value of column [10]

[b] - [e], [1] - [8]: Exhibit HQT-2, Document 1, Table 1, adjusted for maximum investment, O&M held at per kW cost.

[f]: No inflation assumed in this calculation, see text.

[9]: HQT proposed tariff rate, $/kW, inflated at [f]

[10]: [9] - [6] - [7]

In effect, the Company's maximum investment methodology can be interpreted to be very "conservative," where conservative means that existing customers are protected from cost increases resulting from new loads.

ARE THERE REASONS WHY THE RÉGIE MAY HAVE APPROVED SUCH A CONSERVATIVE METHOD?

Yes. First, as is common in North America, the policy was adopted to protect native load from incurring rate increases associated with "merchant" transmission services. The more "conservative" the approach, the more protected is the existing customer base.

Second it is possible that the Régie anticipated that rates would decline under normal utility ratemaking. However, such an expectation would not appear to be consistent with the facts. In Ms. Chang's Table 1, the revenue requirement declines at 2.5 percent in the first year, and is declining at a 4.5 percent rate in the last year. However, HQT's evidence in the R-3903-2014 proceeding shows that the per-kW charge has been reasonably constant (in current dollar terms) over the past 14 years, starting at $72.91 in 2001 and proposed at $74.82 for 2015.[6] This pattern is not surprising, since HQT is presumably replacing older depreciated equipment with newer, higher cost equipment, as well as investing in system reliability upgrades.

Third, the Régie may have wanted to implicitly require new loads to contribute to reliability upgrade costs.[7] In effect, the difference between the rates paid by the new load and the utility revenue requirement for the incremental investment is deemed to be a contribution to reliability improvements. If that is indeed the case, it would likely be more accurate to include an explicit provision for recovery of such costs in the maximum investment calculation, rather than implicitly assuming that revenues earned decline with the revenue requirement.[8]

DOES THIS MAXIMUM INVESTMENT POLICY APPLY EQUALLY TO NATIVE LOAD AND PTP CUSTOMERS?

According to the OATT, the maximum investment policy does apply equally. For example, at Table 3, Ms. Chang applies the same basic calculations as shown above for a PTP customer with a 5-year contract (with my alternative approach shown in Table IEc-3 below).

However, because of the relatively short term nature of the PTP contract, the impact of the bias in the Company's method is smaller. While the 20-year example shows an underestimate of the maximum investment of 19.2 percent ($598 per kW versus $740 per kW), the understatement in the 5-year example is only 9.3 percent ($272 per kW versus $297 per kW). Thus, the Company's very conservative method tends to have a larger negative impact on new long-term customers compared to shorter-term customers.

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[6] Docket R-3903-2014, HQT-12, Document 1, Table 4.

[7] See, for example, HQT-4, Document 6, NLH Part 1 IR-30.

[8] It should be noted that the majority of HQT's investment that is unrelated to new load is basic maintenance, much of which is likely to be asset replacement that may or may not provide a benefit to new loads. HQT-4, Document 6, NLH Part 2 IR-16. Also, to the extent that asset replacement and reliability investments are already reflected in the O&M markup, there is no reason to be even more conservative and assume revenues will decline over time.

TABLE IEc-3

MAXIMUM ALLOWANCE UNDER 5-YEAR DEPRECIATION

[a]	Investment ($/kW)	297	<=== Increase over HQT	9.3%
[b]	Return	5.6660%		
[c]	PV O&M	15.00%		
[d]	Yearly O&M (%)	1.27%		
[e]	Yearly Tax Rate	0.55%		
[f]	Rate/O&M Inflation	0.00%		

Year	Depreci-ation	Rate Base	Cost of Capital	Sub-Total	O&M	Taxes	Revenue Requirement	Revenue	Revenue Less O&M/Taxes
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Start		297							
2014	59	238	17	76	4	2	81.63	**74.65**	69.24
2015	59	178	13	73	4	1	77.94	74.65	69.56
2016	59	119	10	69	4	1	74.24	74.65	69.89
2017	59	59	7	66	4	1	70.55	74.65	70.22
2018	59	0	3	63	4	0	66.86	74.65	70.54
Present Value				**297**	**16**	**4**	**317**	**317**	**297**
			O&M and Tax Percentages ==>		**5.4%**	**1.5%**			

Sources & Notes:

[a]: Derived iteratively from present value of column [10]

[b] - [e], [1] - [8]: Exhibit HQT-2, Document 1, Table 3, adjusted for maximum investment

[f]: No inflation assumed in this calculation, see text.

[9]: HQT proposed tariff rate, $/kW, inflated at [f]

[10]: [9] - [6] - [7]

Moreover, as described in Section VI of Ms. Chang's evidence, HQT proposes to apply a revenue sufficiency test to PTP customers In so doing, HQT compares the revenues earned from a PTP customer to the levelized cost of all of the incremental investments necessary to serve that customer, grossed up for O&M and taxes.

In Table IEc-4 below, I have replicated Ms. Chang's Table 3 which shows this comparison, and I have included the $598 per kW investment that HQT concludes is justified by a $74.65 per kW tariff charge, as well as the $740 per kW maximum investment that I calculate is justified by the $74.65 per kW tariff charge. Note that I prepared this calculation on a per-kW basis rather than the millions of dollars in Ms. Chang's example, but the arithmetic is the same.

TABLE IEc-4

LEVELIZED COST CALCULATION EXAMPLES

[a]	Return	5.666%
[b]	Project Term (years)	20
[c]	O&M (percent)	15.0%
[d]	Taxes (percent)	3.99%

Project	Upgrade Cost Net of Contribution	O&M and Taxes	Total Rolled-in Upgrade Costs	Revenue Less O&M/Taxes
[1]	[2]	[3]	[4]	[10]
A	500	95	595	50.47
B	600	114	714	60.57
C	700	133	833	70.66
D	800	152	952	80.75
E	900	171	1,071	90.85
HQT MaxInv	598	113	711	60.34
RDK MaxInv	740	140	880	74.65

Sources & Notes:

[a] - [d], [2] Exhibit HQT-2, Document 1, Table 8, page 30, assumed.

[3]: ([c]+[d])*[2]

[5]: PMT([a],[b],[2])

As shown in Table IEc-4, HQT would conclude that a $60.35 per kW payment from a PTP customer would be sufficient to cover a $598 per kW investment by HQT. However, under HQT's maximum investment calculations, a $74.65 per kW charge is needed to justify a $598 per kW investment. In contrast, Table IEc-4 also shows that adjusting the Company's maximum investment policy calculation as I suggest above would make it consistent with the Company's "revenue sufficiency" approach. That is, a $740 per kW investment would meet the revenue sufficiency test proposed by HQT for its PTP customers with revenue of $74.65 per kW.

Thus, HQT's revenue sufficiency test is inconsistent with its maximum investment calculation methodology.

DOES THE LEVELIZED COST TEST REFLECT A REQUIREMENT THAT NEW LOAD CONTRIBUTE TO RELIABILITY AND SYSTEM QUALITY IMPROVEMENTS?

It does not appear to do so.[9] Thus, if the Régie determines that the existing method for calculating the maximum investment level is reasonable, the levelized cost calculation would need to be modified to be consistent.

IN THIS PROCEEDING, HQT PROPOSES TO RETAIN THE 20-YEAR RECOVERY PERIOD FOR CALCULATING THE MAXIMUM INVESTMENT LEVEL FOR NATIVE LOAD SERVICE. IS THIS A REASONABLE APPROACH?

I do not believe that it is. As the operating lifetime for the investments made to attach new customers is approximately 40 rather than 20 years, and since native load customers have no legal or reasonable alternative to taking transmission service from HQT, it is not clear why HQT proposes to limit the period over which it can reasonably expect to earn revenues associated with a system expansion required by new native load customers.

HQT justifies this approach as being "conservative" in respect of its customer contribution policy. What this presumably means is that HQT is providing extra protection for existing customers from expansion costs related to new customers. This is neither conservative nor aggressive; it is simply a bias in favor of existing customers at the expense of new native load customers.

Increasing the recovery period for native load investments to 40 years serves to increase the maximum investment level from the $740 per kW shown in Table IEc-2 to $969 per kW. The supporting details for this calculation are shown in Exhibit IEc-2 Schedule 1 attached to this evidence.

IS THE APPLICATION OF THE LEVELIZED COST TEST FOR PTP LOAD LIMITED TO A 20-YEAR PERIOD?

To my knowledge, it is not. Revenues from PTP customers will continue to be recognized in the levelized cost test as long as revenues are provided by the customer. In contrast, the maximum investment test implicitly limits revenues to a 20-year period. Thus, the application of the levelized cost test for PTP loads results in a bias in favor of new PTP loads over new native loads.

HOW DOES HQT ADDRESS SITUATIONS IN WHICH THE NEW LOAD IS PHASED IN OVER TIME?

As I understand it, HQT treats the full load growth over the forecast period as being in place for the entire period. In so doing, HQT is implicitly assuming that

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[9] I interpret HQT-4, Document 1, Régie IR-2.4 to imply that the 15 percent O&M gross-up factor represents only direct O&M costs, and does not include costs associated with replacement capital and system reliability upgrades.

the total new load will be generating incremental revenues for the entire period, when in fact that incremental revenue will start low and grow over time.

Unlike HQT's other assumptions which generally favor existing customers over new customers, this one overstates the revenue value associated with new customers, potentially leaving a shortfall for existing customers. An example of the impact of phasing in the new load is shown in Exhibit IEc-2, Schedule 2.

DOES HQT FACTOR IN ANY RATE INFLATION INTO THE EXPECTED REVENUES FROM NEW CUSTOMERS?

Like many utilities, HQT does not. However, as I noted earlier, HQT has experienced relatively stable rates over the past 14 years. Excluding an inflation adjustment is therefore reasonable at this time. However, if HQT's demand charge starts to rise, it may be reasonable to incorporate such a factor into the maximum investment calculation.

DOES THE LEVELIZED COST CALCULATION REFLECT INFLATION?

As I understand it, the levelized cost test will rely on actual revenues from PTP customers rather than the implicit assumption in the maximum investment calculation that revenues will remain the same or decline. Thus, to the extent that there is an increase in tariff rates, the PTP customers receive a benefit in the levelized cost test, whereas no inflation is reflected in the maximum investment test.

HOW DOES HQT INCORPORATE O&M COSTS INTO DETERMINING THE MAXIMUM INVESTMENT TEST?

HQT reports that it calculates an O&M historical cost per kW at $9.11 per kW for 2012, which it determines is 1.6 percent of the maximum investment value based on a 20-year life.[10] However, the Company uses a 1.23 percent factor for O&M costs in calculating the maximum investment amount in the 20-year calculations, and a 0.96 percent of costs for the 40-year calculations. The values for the 20-year and 40-year calculations produce a net present value for O&M costs that equals 15 percent of the investment amount. This 15 percent value is essentially based on precedent, and has been used for many years.[11]

HQT applies the 1.27 percent factor to shorter-term calculations. Presumably, if the Régie were to direct HQT to adopt a 40-year recovery period in the maximum investment calculation, HQT would lower the O&M annual percent to 0.96 percent.

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[10] HQT-4, Document 3, AQCIE/CIFQ IR-3(a).

[11] HQT-3, Document 1, page 7.

While this approach is not unreasonable, it does appear that the O&M rate used in the maximum investment calculation falls short of HQT's current O&M costs. At a minimum, the Régie should monitor the costs to ensure that the traditional 15 percent rule remains reasonable.

WHAT ARE THE ISSUES REGARDING THE COST OF CAPITAL USED IN THE DEVELOPMENT OF THE MAXIMUM INVESTMENT LEVEL?

In my experience, utilities generally use their approved weighted average cost of capital, although the treatment of income tax effects can vary among utilities. In HQT's case, the Company uses its prospective cost of capital, and argues that it should use a longer-term forecast of its cost of capital, rather than the most recent approved historical cost value.[12] This is a reasonable approach, since the investments in question are clearly prospective.

OVERALL, WHAT DO YOU CONCLUDE FROM YOUR ASSESSMENT OF THE MAXIMUM INVESTMENT CALCULATION?

Overall, the maximum investment calculation appears to be extremely conservative, and it is not clearly consistent with the language in the tariff. Moreover, the arithmetic basis for the maximum investment calculation, as well as the treatment of certain cost factors, is not consistent between the maximum investment test and the levelized cost test. This inconsistency implicitly results in disparate treatment of native load and PTP customers.

3. APPLICATION OF MAXIMUM INVESTMENT CREDIT TO NATIVE LOAD

HQT INDICATES THAT IT PROPOSES TO MODIFY THE TREATMENT OF MAXIMUM INVESTMENT LEVELS FOR NATIVE LOAD PROJECTS RELATED TO GENERATION (OR "RESOURCE") RELATED PROJECTS. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPANY'S CURRENT POLICY.

HQT earns revenues associated with load.[13] However, under the existing maximum investment policy as detailed in Table 5 of Ms. Chang's evidence, it appears that, under current policy, the maximum investment amount is applied to both resource additions and load additions, even though incremental revenues are earned only from the load. As I understand Table 5, Ms. Chang posits an

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[12] HQT-4, Document 2, ACEFO IR-15.

[13] While service to native load customers is expressed in the tariff as a fixed dollar amount, the magnitude of that dollar amount is derived by allocating HQT's revenue requirement among the rate classes based on peak demand. Thus, an increase in peak demand for native load will result in an increase in HQT's revenues, all other factors being equal. By contrast, an increase in generating capacity that is designed to serve native load does not, by itself, result in any increase in HQT revenues.

example of a 100 MW growth in native load, which requires an investment of $137.1 million in load-related projects (substations) and $100 million in generation integration projects. HQT then applies its maximum investment amount of $598 per kW to both the substation projects and to the generation projects, resulting in a credit of 2 * $598/kW * 100,000 kW = $119.6 million.[14] Since the combined cost of the project is $237.1 million, HQT calculates a contribution requirement of $237.1 - $119.6 = $117.5 million, which is then grossed up by 15 percent for O&M and taxes to $135.2 million.[15] However, since HQT will only earn incremental revenues associated with the load growth, the maximum investment credits appear to be inappropriately double-counted.

HOW DOES HQT PROPOSE TO MODIFY THIS POLICY?

Ms. Chang goes on to present three examples of how the proposed contribution policy for native load projects will work, in Table 6. All three examples involve load growth of 400 MW, while retaining an "allocation unit" of 100 MW associated with resource-related projects. Ms. Chang clarifies that the allocation units for the resource projects represent the full capacity of the generation project, which may or may not be related to the load growth.[16]

IS THIS A LOGICAL APPROACH?

Based on my understanding at this time, it is not. Resource-related projects only generate incremental revenue for HQT if they are associated with load growth. Thus, in those cases where HQT is integrating a new generator that has no associated load growth, the responsibility for the investment cost should lie with the generator.

For example, suppose HQP opts to close a 200 MW generator that is supplying native load to HQD and replace it with a 200 MW generator in another location, which will require HQT to invest $50 million in generation integration facilities. As there is no incremental revenue for HQT from this project, the cost should be recovered from HQP (including gross-up for O&M and taxes). Whether that $50

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[14] For the purpose of this section of evidence, I rely on the Company's claimed maximum investment credit of $598 per kW, rather than the alternative proposal presented in Section 2 above.

[15] HQT proposes to use a 15 percent gross-up factor for the customer contribution regardless of the duration of the project, whereas the maximum investment calculation assumes a very different O&M/tax markup depending on the life of the project. For example, in Ms. Chang's 20-year example in Table 1 implies a 19 percent markup whereas the 5-year example implies a 7 percent markup. See, for example, HQT-4, Document 2, ACEFO IR-18.2.

[16] HQT-4, Document 3, AQCIE/CIFQ IR-5.

million is passed on directly to HQD in the form of an upfront payment or whether it is recovered from HQD through contract rates is a matter that should be determined by the contractual arrangement between HQP and HQD.

In addition, in the case where the new generation is directly associated with new load, it is unclear why HQT proposes to limit the amount of the credit associated with the new load that can be used to offset the costs associated with the new generation. Consider Scenario 1 in Ms. Chang's Table 6. The net increase in load is 400 MW, which HQT calculates should provide a credit of $239 million (400 MW * $598/kW). The combined cost of the generation project ($100 million) and the substation projects ($100 million) is $200 million. From a common sense perspective, one would logically assume that the incremental revenues exceed the incremental cost for the combined projects and no contribution would be required.

However, under the methodology detailed in Table 6, HQT will continue to calculate a credit associated with the 100 MW generation project. In Ms. Chang's example, this results in an arbitrary split of the $100 million generation investment into a "rolled-in" portion and a "contribution" portion. The rolled-in amount is based on applying the $598 per kW maximum investment credit to the 100 MW, or $59.8 million. The contribution portion is the difference between the $100 million cost and the rolled-in portion. However, unlike the current methodology in which HQT provides this $59.8 million in investment, this $59.8 million must be provided by the load customer. HQT therefore proposes to either require the new customer to make that $59.8 million contribution directly (Scenario 3 in Table 6), or to offset the $59.8 million in excess credits related to load projects (Scenario 1).[17]

While this approach is certainly an improvement over the existing methodology (in which maximum investment credits are double counted by being applied to both generation and load projects), it remains unclear why excess maximum investment credits on the load side may only be used to offset the "rolled-in" portion of generation investment and not the total cost of the resource-related investment.

For example, consider the scenarios shown in Table IEc-5 below.

[17] Scenario 2 is a hybrid of those examples, with the $59.8 million being partly offset by excess load maximum investment credit and the balance funded by contribution.

TABLE IEc-5 HQT PROPOSED METHOD FOR NATIVE LOAD PROJECTS ALTERNATIVE VERSION OF MS. CHANG'S TABLE 6, SCENARIO 1			
		Scenario 1	**Scenario 1A**
	Step 1: Calculate Maximum Allowance Based on Allocation Units of the Resource-Related Projects		
[a]	Project Cost	100	50
[b]	Allocation Units (MW)	100	100
[c]	Maximum Allowance ($/kW)	598	598
[d]	Total Maximum Allowance for Resource-Related Project	59.8	59.8
	Step 2: Calculation Contribution for Resource-Related Projects		
[e]	Total Contribution*	40.2	0.0
[f]	Rolled-in Portion of Upgrade Costs	59.8	59.8
	Step 3: Calculation Contributons/Credits of Other Projects		
[g]	Substation A Project Cost	20	30
[h]	Substation B Project Cost	20	30
[i]	Substation C Project Cost	20	30
[j]	Substation D Project Cost	20	30
[k]	Substation E Project Cost	20	30
[l]	Total Substation Project Cost	100	150
[m]	Allocation Units (MW)	400	400
[n]	Maximum Allowance ($/kW)	598	598
[o]	Total Maximum Allowance	239.2	239.2
[p]	Total Contribution/(Credit)*	(139.2)	(89.2)
	Step 4: Measure Credits (if any) Against Remaining Contribution from Resource-Related Projects		
[q]	Are There Credits Left Over from Other Projects in Step 3?	Yes	Yes
	Step 5: Calculate Total Contribution		
[r]	Resource-Related Contribution from Step 1	40.2	0.0
[s]	Rolled-in Portion of Resource-Related Upgrade Cost Not Covered by Load-Based Credits	0.0	0.0
[t]	Total Resource Project Contribution	40.2	0.0
[u]	O&M (15%)	6.0	0.0
[v]	Total Contribution for Resource-Related Project	46.2	0.0
[w]	Total Contribution for Other Projects	0.0	0.0
[x]	**Total Contribution (Resource-Related & Other Projects)**	**46.2**	**0.0**

Sources and Notes

* Before application of 15% O&M.

Note that both the total project costs ($200 million) and the calculations are the same in each column, with the difference coming from the relative cost of resource-related and load-related projects.

See Exhibit HQT-2, Table 6 for assumptions and calculations, except that [e] may not be negative.

This table compares the implications of Scenario 1 in Ms. Chang's Table 6 with an alternative scenario. In my alternative scenario, there is no change in allocation units, there is no change in total project cost, and there is no change in load growth. I have simply modified Ms. Chang's example such that, rather than cost of $100 million for both resource and substation projects, I assume costs of $50 million for resource projects and $150 million for substation projects. Despite the fact that the total costs and total revenues of both scenarios are identical, Ms. Chang's scenario requires a contribution of $46.3 million and the alternative requires no contribution. It is not clear why the contribution required for a $200 million project which results in incremental load of 400 MW will differ depending on whether the investments are in generation integration facilities or substations.

Moreover, strict adherence to the computational algorithm shown in Ms. Chang's Table 6 may also produce counter-intuitive results for the other examples. In particular, Ms. Chang's scenarios 2 and 3 produce very sensible results, in that the required contribution in total is simply the difference between the project cost and the incremental load multiplied by the maximum investment. However, unless the "contribution" related to resource-related projects is allowed to be negative, the algorithm as written will require a larger contribution if the overall project has lower generation costs and higher substation costs. These results are shown in Exhibit IEc-2, Schedules 3 and 4.

IS THE PROBLEM OF THE UNUSED CREDIT IN SCENARIO 1 LIKELY TO RESULT IN HIGHER THAN NECESSARY CONTRIBUTIONS FROM HQD?

It may not. The Company indicates that the unused credit may be applied against other projects within the annual aggregation.[18] To the extent that the unused credit contributes to an excess credit at the end of the annual aggregation, the carry-forward policy would presumably allow HQD to use this credit in the future. Nevertheless, it is unclear why the credit from incremental load is not simply applied to both the load-related and resource-related projects directly in the year when it occurs.

DOES HQT PROPOSE TO AGGREGATE NATIVE LOAD GROWTH PROJECTS FOR DEVELOPING A REQUIRED CONTRIBUTION?

It does. HQT proposes to aggregate all expansion projects and related load growth within a year to evaluate the required contribution for that year. If a net contribution is due, HQD will make the contribution. If a surplus remains (meaning the maximum investment exceeds the incremental cost), that surplus is carried forward and may be applied to future year contribution requirements. In effect, as long as that surplus is eventually used, the incremental native load provides no contribution to the existing grid.

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[18] HQT-4, Document 3, IR-6(d).

4. APPLICATION OF MAXIMUM INVESTMENT CREDIT TO PTP LOAD

HOW WILL THE MAXIMUM CREDIT BE APPLIED TO PTP CUSTOMERS?

As I noted earlier, HQT indicates that the maximum approach will be applied to PTP customers as applies to native load customers. However, from a practical perspective, it appears that HQT will primarily rely on the levelized cost methodology for assessing the adequacy of PTP revenues, supplemented by allowing PTP customers to use any extra revenues to pre-pay investment requirements.

At present, HQT has three PTP customers: Hydro Québec Production ("HQP"), Brookfield Energy Marketing ("EBM") and Newfoundland and Labrador Hydro ("NLH"). Of these HQP represents the vast majority of long-term PTP revenues, at $309 of $349 million.[19] In addition, it is my understanding that the incremental costs associated with providing service to EBM and NLH are relatively small, such that the rates paid by these PTP customers exceed incremental costs. Thus, these customers are now presumably contributing to the fixed costs of the existing infrastructure by paying the regular tariff rate. These customers, at least to date, have therefore been reasonably subject to the "higher of" regulatory policy.

For HQP, my understanding of how HQT applies the levelized cost test rule is as follows:[20]

- First, all HQP service agreements and cost requirements are bundled together and evaluated as a whole, rather than individually.[21]
- Second, HQT compares the revenues from the PTP agreements with the levelized annual costs associated with incremental projects.
- If the revenues do not cover the levelized annual cost, it is my understanding that a supplemental contribution would be required of HQP.
- If the revenues exceed levelized annual cost, rather than use the excess revenues to make a contribution to the fixed cost of the existing infrastructure, HQT allows HQP to use the excess to pay down the remaining "principal" on the incremental investments. HQT refers to this as a "complementary repayment."

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[19] HQT-4, Document 1, Régie IR 16.2.

[20] Presumably this approach would also apply to EBM and NLH, if they were to require future investments.

[21] It is acknowledged that native load revenues and investment projects are similarly bundled.

The practical result of this approach is that it appears that HQP has made no contribution to the fixed cost of the existing grid since 2008.[22]

CAN YOU DEMONSTRATE THAT CONCLUSION FROM HQT'S EXHIBITS?

Table IEc-6 below summarizes the revenues and costs related to HQP's PTP service from 2009 to 2014. Over that period, HQP contributed revenues of some $1,692 million, related to its long and short-term transportation agreements. The incremental annualized costs incurred by HQT associated with providing that service are reported at $827 million, leaving an $865 million surplus. However, rather than apply that surplus to offset the costs of the existing infrastructure, HQT uses the excess to pay down the incremental investment costs incurred to provide service to HQP. For example, these excess revenues have been used to pay down the entire investment in the Ontario interconnection, and will be used starting in 2014 to contribute to the integration costs of the Romaine generating complex.[23]

TABLE IEc-6

SUMMARY OF HQP PTP REVENUES AND INCREMENTAL COSTS ($mm)

	Actual			*Forecast*			
	2009	2010	2011	2012	2013	2014	**Simple Sum 2009 - 2014**
[1]	[2]	[3]	[4]	[5]	[6]	[7]	**[8]**
Applicable Incremental Revenues	197.4	309.4	304.9	289.5	283.4	307.1	**1,691.7**
Annualized Cost of Incremental System Additions [a]	88.7	139.7	147.1	155.6	156.4	139.5	**827.0**
Revenues in Excess of Incremental Costs	108.7	169.7	157.8	133.9	127.0	167.6	**864.7**
Excess Revenues Applied to Pay Down Incremental Investment	108.7	169.7	157.8	133.9	127.0	167.6	**864.7**
Excess Revenues Applied to Existing Infrastructure, Reliability and Quality	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**

Source: Exhibit HQT-1 Document 1, Annexe 2, Revised 31 October 2014

Notes:

[a] Includes Toulnustuc-style and 12A.2(i) projects.

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[22] This conclusion is based on my understanding of Exhibit HQT-1, Document 1, Annexe 2, as well as the discussion of the complementary repayment at HQT Document 1, Section 8.1.

[23] It is my understanding that the Romaine complex investment will not result in any incremental transmission revenues to HQT beyond those already reserved by HQP.

IS THIS APPROACH COMPARABLE TO HQT'S PROPOSED APPROACH OF CARRYING FORWARD UNUSED MAXIMUM INVESTMENT CREDITS FOR NATIVE LOAD?

There are conceptual similarities. Like the native load maximum investment policies, unused surpluses can be applied against future shortfalls. Thus, as long as expansion projects continue, neither incremental native load nor incremental HQT PTP load will contribute to the existing infrastructure, or to reliability and product quality investments. While this approach, if implemented correctly, will achieve the goal of protecting existing customers from costs associated with new customers, it fails to provide any reasonable sharing of the costs of existing infrastructure. In effect, rather than a "higher of" policy, HQT's proposal looks much more like a pure "incremental cost" methodology, as far as native load and HQP are concerned.

However, the native load and HQP situations are unlike with respect to equity. Native load customers are already paying the full cost of the existing infrastructure that is used by both native load and HQP. While HQT's policy appears to treat *new* native load and *new* PTP customers equally (once the arithmetic differences are corrected), the policy essentially locks in the requirement that native load customers bear the huge majority of the costs for existing infrastructure.

BEYOND THE INEQUITY OF HQP MAKING NO CONTRIBUTION TO THE EXISTING GRID, DOES THIS APPROACH CREATE ANY OTHER ECONOMIC DISTORTIONS?

It may. In 2009, HQP entered into three service agreements with HQT for a total of 3650 MW, of which 2400 MW are for a 35-year period and 1250 MW have a 50-year period. These agreements will produce revenues of $288 million in 2014, and HQT will continue to earn revenues through at least 2044. In contrast, the annualized incremental costs for service to HQP in 2014 were about $140 million. Absent additional investment, these annualized incremental costs will stay the same or decline. Thus, these long term contracts are producing an annual surplus of at least $148 million. Under HQT's policy, this surplus is a free resource for HQP, but not for other ratepayers.

Suppose, hypothetically, that HQP identifies an export project that it can serve within its existing HQT commitments, and which will produce an additional $200 million per year in revenues. Suppose further that this project requires investment in generating facilities that have an annualized costs of $150 million per year, and incremental annualized transmission costs of $100 million per year. From a straight economic standpoint, and from a policy perspective in Québec, this project is a loser. Revenues are $200 million per year and annualized incremental costs are $250 million per year.

Unfortunately, under HQT's method, it is my understanding that HQP would be allowed to apply its current annual surplus against the incremental transmission costs. Thus, from HQP's perspective, it earns additional revenues of $200 million per year at a cost of $150 million per year, while the incremental $100 million per year in transmission investments are rolled into HQT's rate base and recovered from all other customers.

Thus, for the specific circumstances in Québec as they now exist, HQT's policy may give HQP an incentive to invest in projects that are economically inefficient to Québec as a whole, but which result in a net benefit to itself and a cost to other HQT ratepayers (both native load and other PTP customers).

DO OTHER REGULATORS ALLOW CUSTOMERS TO AGGREGATE PROJECTS AND CARRY FORWARD MAXIMUM INVESTMENT CREDITS, EXPLICITLY OR IMPLICITLY, AS PROPOSED BY HQT?

Customer contribution policies vary widely from utility to utility and jurisdiction to jurisdiction, and it is not easy to specify a standard practice. Moreover, this variation results from the specific circumstances facing the utility and the jurisdiction, and the policies are tailored to address those concerns. So it should be in Québec.

However, having said that, it is my experience that customer contribution policies are generally determined at the time a new customer signs on for service, and apply to one project at a time. At that time, both incremental revenues and incremental costs are assessed, and any customer contribution determined. In general, any unused contributions are not carried forward, and levelized incremental cost tests are unnecessary.

Based on the response to discovery, it is my understanding that Ms. Chang generally agrees with this assessment, at least as far as aggregating projects for any particular customer.[24]

IS THERE AN ALTERNATIVE APPROACH THAT RETAINS COMPARABLE TREATMENT OF NATIVE LOAD AND HQP PTP LOAD?

The obvious general alternative would be to reject the idea of unused investment credit carry-forwards. Native load projects would be evaluated based on the specific incremental revenues that they generate and the incremental costs that they cause, and customer contribution requirements determined accordingly. PTP service agreements would be evaluated when they are entered into, with

[24] HQT-4, Document 5, FCEI IR-7.8.

incremental revenues, incremental costs and contribution requirements determined at the time.[25]

5. CONCLUSIONS

PLEASE SUMMARIZE YOUR CONCLUSIONS.

Based on the information available at this time, I conclude the following:

- As proposed, there is an arithmetic inconsistency between the development of the maximum investment credit and the levelized cost proposal that should be reconciled. The simplest approach for doing so would be to set the maximum investment amount based on levelized annual revenues.
- HQT's calculation of the maximum investment credit for native load projects should be based on a 40-year term.
- Maximum investment credits should not be applied to resource-related projects, for either native load or PTP projects, unless those projects are related to revenue-producing load growth. The economic test for native load should not arbitrarily differentiate between resource-related and load-related projects, such that a contribution may be required even when incremental revenues exceed incremental costs as HQT proposes.
- To balance economic efficiency and equity considerations in the "higher of" regulatory principle, unused maximum investment credits, either explicit or implicit in the levelized cost test, should not be carried forward. This will allow at least some new customers to contribute to the costs of the existing infrastructure from which they benefit.

[25] Note that this approach would have the competitive advantage of discouraging a single PTP customer from locking up capacity in advance for long periods of time, and then using the "free" resource of unused investment credits to fund projects on an "as you go" basis.

EXHIBIT IEc-1

CURRICULUM VITAE AND

EXPERT TESTIMONY SCHEDULE

OF

ROBERT D. KNECHT

IEc

INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

Robert D. Knecht specializes in the practical application of economics, finance and management theory to issues facing public and private sector clients. Mr. Knecht has more than thirty years of consulting experience, focusing primarily on the energy, metals, and mining industries. He has consulted to industry, law firms, and government clients, both in the U.S. and internationally. He has participated in strategic and business planning studies, project evaluations, litigation and regulatory proceedings and policy analyses. His practice currently focuses primarily on utility regulation, and he has provided analysis and expert testimony in numerous U.S. and Canadian jurisdictions. Mr. Knecht also served as Treasurer of IEc from 1996 through 2010, and was responsible for the firm's accounting, finance and tax planning, as well as administration of the firm's retirement plans, during that period.

Mr. Knecht's consulting assignments include the following projects:

- For the Pennsylvania Office of Small Business Advocate, Mr. Knecht provides analysis and expert testimony in industry restructuring, base rates and purchased energy cost proceedings involving electric, steam and natural gas distribution utilities. Mr. Knecht has analyzed the economics and financial issues of electric industry restructuring, stranded cost determination, fair rate of return, claimed utility expenses, cost allocation methods and rate design issues.
- For industrial customers in Québec, Mr. Knecht has prepared economic analysis and expert testimony in regulatory proceedings regarding cost allocation, compliance with legislative requirements for cross-subsidization, and rate design.
- For the New Brunswick Public Intervenor, Mr. Knecht has prepared expert testimony regarding electric and gas utilities, on various regulatory issues, including revenue requirements, amortization methods, system expansion economics, cost allocation, and rate design
- For independent power producers and industrial customers in Alberta, Mr. Knecht has provided analysis and expert testimony in a variety of electric industry proceedings, including industry restructuring, cost unbundling, stranded cost recovery, transmission rate design, cost allocation and rate design.
- As a participant on various international teams of experts, Mr. Knecht has prepared the economic and financial analysis for industry restructuring studies involving the steel and iron ore industries in Venezuela, Poland, and Nigeria.
- For the U.S. Department of Justice and for several private sector clients, Mr. Knecht has prepared analyses of economic damages in a variety of litigation matters, including ERISA discrimination, breach of contract, fraudulent conveyance, natural resource damages and anti-trust cases.
- Mr. Knecht participates in numerous projects with colleagues at IEc preparing economic and environmental analyses associated with energy and utility industries for the U.S. Environmental Protection Agency and other private and public entities.

Mr. Knecht holds a M.S. in Management from the Sloan School of Management at M.I.T., with concentrations in applied economics and finance. He also holds a B.S. in Economics from M.I.T. Prior to joining Industrial Economics as a principal in 1989, Mr. Knecht worked for seven years as an economic and management consultant at Marshall Bartlett, Incorporated. He also worked for two years as an economist in the Energy Group of Data Resources, Incorporated.

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ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
P-2014-2417907	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, class eligibility, reconciliation
R-2014-2406274	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2407345	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Customer contribution policy, alternative financing mechanism
R-2014-2408268	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2014	Pennsylvania Office of Small Business Advocate	Gas procurement sharing mechanism, cost allocation
R-2014-2397237	Pennsylvania Public Utility Commission	Pike County Light & Power (Electric)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2397353	Pennsylvania Public Utility Commission	Pike County Light & Power (Gas)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation
R-2014-2399598	Pennsylvania Public Utility Commission	Peoples TW Phillips	March 2014	Pennsylvania Office of Small Business Advocate	Gas procurement, design day demand, cost allocation rate design, retainage
P-2013-2389572 (Remand)	Pennsylvania Public Utility Commission	PPL Electric Utilities	February 2014	Pennsylvania Office of Small Business Advocate	Time of use rates, net metering rates
Matter 225	New Brunswick Energy & Utilities Board	Energy Gas New Brunswick	January 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2013-2391368, P-2013-2391372, P-2013-2391375, P-2013-2391378	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, West Penn Power	January 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, cost allocation, rate design

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EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter No. 214	New Brunswick Energy & Utilities Board	Generic	November 2013	New Brunswick Public Intervenor	Maximum retail margins for motor fuel and residential heating oil.
Matter No. 171	New Brunswick Energy & Utilities Board	New Brunswick Power	September 2013	New Brunswick Public Intervenor	Amortization method for deferral costs associated with refurbishing Point Lepreau Generating Station
C-2013-2367475	Pennsylvania Public Utility Commission	PPL Electric Utilities	August 2013	Pennsylvania Office of Small Business Advocate	Forecasting and reconciliation of default service electric costs and revenues.
P-2011-2277868, I-2012-2320323	Pennsylvania Public Utility Commission	Generic	August 2013	Pennsylvania Office of Small Business Advocate	Ratemaking treatment for customers in overlapping NGDC service territories (“gas-on-gas”).
P-2013-2356232	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Program design, cost recovery and rate design for alternative system expansion financing pilot program (“GET Gas”)
R-2013-2355886	Pennsylvania Public Utility Commission	Peoples TWP LLC	July 2013	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2013-2361764, R-2013-2361763, R-2013-2361771	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas.
R-2013-2341604	Pennsylvania Public Utility Commission	Peoples TWP	March 2013	Pennsylvania Office of Small Business Advocate	Retainage rates, design day demand forecast, allocation of demand costs, recovery of other gas costs
R-2013-2341534	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2013	Pennsylvania Office of Small Business Advocate	Unaccounted for gas, retainage.
R-2012-2333993	Pennsylvania Public Utility Commission	Philadelphia Gas Works	February 2013	Pennsylvania Office of Small Business Advocate	Gas purchase cost unbundling, uncollectible cost unbundling

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2012-2321748	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	January 2013	Pennsylvania Office of Small Business Advocate	Cost of capital, cost allocation, revenue allocation, gas procurement cost unbundling, rate design
R-2012-2327529	Pennsylvania Public Utility Commission	Peoples TWP	December 2012	Pennsylvania Office of Small Business Advocate	Gas purchase cost unbundling, price to compare
R-2012-2314235 R-2012-2314224 R-2012-2314247	Pennsylvania Public Utility Commission	UGI Utilities Gas Division UGI Penn Natural Gas UGI Central Penn Gas	October 2012	Pennsylvania Office of Small Business Advocate	Gas purchase cost unbundling, reconciliation, migration rider
P-2012-2302074	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2012	Pennsylvania Office of Small Business Advocate	Default service procurement, rate design, reconciliation, working capital cost treatment.
Matter No. 178	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	July 2012	NB Public Intervenor	System expansion economic test, test year revenue requirement, cost allocation, rate design, treatment of stranded costs.
R-2012-2290597	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2012	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2012-2293303	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2012	Pennsylvania Office of Small Business Advocate	Treatment of pipeline credits
AUC ID #1633	Alberta Utilities Commission	Alberta Electric System Operator	April 2012	Powerex, Northpoint Energy Solutions, Cargill	Economic efficiency issues for allocation of constrained transmission capacity.
R-2012-2286447	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, reconciliation
R-2012-2281465	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, gas price procurement and hedging

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EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2011-2273539	Pennsylvania Public Utility Commission	Peoples TWP	March 2012	Pennsylvania Office of Small Business Advocate	Design day demand methodology
P-2011-2273650 P-2011-2273668 P-2011-2273669 P-2011-2273670	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power	February 2012	Pennsylvania Office of Small Business Advocate	Default service procurement, retail market enhancement, rate design.
R-2011-2264771	Pennsylvania Public Utility Commission	PPL Electric Utilities	January 2012	Pennsylvania Office of Small Business Advocate	TOU Rates
P-2011-2256365	Pennsylvania Public Utility Commission	PPL Electric Utilities	November 2011	Pennsylvania Office of Small Business Advocate	Default service reconciliation
Matter No. 132	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	October 2011	New Brunswick Public Intervenor	Revenue requirement, cost forecasting, system expansion economic test, regulatory deferral test, filing requirements.
R-2010-2161694 on Remand	Pennsylvania Public Utility Commission	PPL Electric Utilities	August 2011	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables
R-2011-2238943, R-2011-2238943, R-2011-2238949,	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division), UGI Central Penn Gas UGI Penn Natural Gas	July 2011	Pennsylvania Office of Small Business Advocate	Design day demand, mandatory capacity assignment, sharing mechanisms
C-2011-2245906, M-2011-2243137	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2011	Pennsylvania Office of Small Business Advocate	Reconciliation of default service costs and revenues
P-2011-2218683, P-2011-2224781	Pennsylvania Public Utility Commission	West Penn Power Company	April, May 2011	Pennsylvania Office of Small Business Advocate	Critical peak pricing, time-of-use pricing

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2010-2214415	Pennsylvania Public Utility Commission	UGI Central Penn Gas	April 2011	Pennsylvania Office of Small Business Advocate	Equity cost of capital, cost allocation, revenue allocation, non-residential rate design, EE&C cross-subsidies and cost recovery, natural gas vehicle subsidies
R-2010-2215623, R-2010-2201974	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	April 2011	Pennsylvania Office of Small Business Advocate	Cost of equity capital, cost allocation, revenue allocation, BTU adjustment mechanism, rate design, DSIC
NBEUB 2010-017	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	April 2011	New Brunswick Public Intervenor	Cost- and market-based ratemaking, transition mechanism
M-2010-2210316	Pennsylvania Public Utility Commission	UGI Utilities, Electric Division	March 2011	Pennsylvania Office of Small Business Advocate	Energy efficiency plan cost recovery, conservation development rider
A-2010-2213893, et al.	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	February 2011	Pennsylvania Office of Small Business Advocate	Asset valuation, reasonableness of proposed affiliate transaction
M-2009-2123944	Pennsylvania Public Utility Commission	PECO	January 2011	Pennsylvania Office of Small Business Advocate	Dynamic pricing cost allocation and rate design
NBEUB 2010-007	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	December 2010	New Brunswick Public Intervenor	Allowable costs, O&M capitalization policy, expansion cost effectiveness, incentive mechanisms
R-3740-2010	Régie de l'énergie, Québec	Hydro Québec Distribution	December 2010	AQCIE/CIFQ	Pension cost reconciliation, cross-subsidies, rate design
P-2010-2158084	Pennsylvania Public Utility Commission	West Penn Power Company	November 2010	Pennsylvania Office of Small Business Advocate	Transmission service charge, reconciliation timing
P-2010-2194652	Pennsylvania Public Utility Commission	Pike County Light & Power	November 2010	Pennsylvania Office of Small Business Advocate	Electric default service procurement, customer education

IEc

INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
A-2010-2176520, A-2010-2176732	Pennsylvania Public Utility Commission	Allegheny Power/FirstEnergy Corporation	September 2010	Pennsylvania Office of Small Business Advocate	Implications of proposed merger for default service
App. No. 1605961, Proceeding ID 530	Alberta Utilities Commission	Alberta Electric System Operator	August 2010	BC Hydro	Transmission rate design
R-2010-2167797	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	July 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables, rate of return
R-2010-2172933, R-2010-2172922, R-2010-2172928	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division), UGI Central Penn Gas UGI Penn Natural Gas	July 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, unaccounted-for gas, retainage
NBEUB 2010-002	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	June 2010	New Brunswick Public Intervenor	Cost allocation, rate design, deferral costs
R-2010-2161694	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables
R-2010-2161920	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, retainage rates, gas price forecasting
R-2009-2149262	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, rate of return
P-2009-2145498	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division)	April 2010	Pennsylvania Office of Small Business Advocate	Merchant function charge, purchase of receivables
R-2010-2157062	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs
NBEUB 2009-017	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	March 2010	New Brunswick Public Intervenor	Cost allocation, deferral costs

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2009-2139884	Pennsylvania Public Utility Commission	Philadelphia Gas Works	March 2010	Pennsylvania Office of Small Business Advocate	Revenue requirement, cost allocation, rate design, DSM program
R-2010-2150861	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs
R-2009-2145441	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	March 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, unaccounted-for gas, retainage
P-2010-2099333	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	February 2010	Pennsylvania Office of Small Business Advocate	Purchase of receivables
R-3708-2009	Régie de l'énergie, Québec	Hydro Québec Distribution	November 2009	AQCIE/CIFQ	Post-patrimonial generation cost allocation, revenue allocation
M-2009-2123944, 2123948, 2123950, 2123951	Pennsylvania Public Utility Commission	PECO, Duquesne Light, Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power	October, November 2009	Pennsylvania Office of Small Business Advocate	Smart Meter Cost Allocation and Rate Design
NBEUB 2009-006	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2009	New Brunswick Public Intervenor	Development Period Criteria
M-2009-2092222, 2121952, 2112956, 2093218, 2093217, 2093215	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power, Duquesne Light, PPL Electric	August 2009	Pennsylvania Office of Small Business Advocate	Energy efficiency and conservation programs, cost allocation, rate design
1604944; ID# 184	Alberta Utilities Commission	ATCO Gas	July 2009	Rate 13 Group	Cost allocation, rate design
R-2009-2105904, 909, 911	Pennsylvania Public Utility Commission	UGI Penn Natural Gas, UGI Central Penn Gas, UGI Utilities Inc. Gas Division	July 2009	Pennsylvania Office of Small Business Advocate	Gas supply procurement hedging, unaccounted-for gas, revenue sharing mechanisms

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2009-2093219	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2009	Pennsylvania Office of Small Business Advocate	Revenue sharing mechanisms, retainage rate, gas procurement
R-2008-2079660	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	May 2009	Pennsylvania Office of Small Business Advocate	Equity cost of capital, cost allocation, rate design
R-2008-2079675	Pennsylvania Public Utility Commission	UGI Central Penn Gas	May 2009	Pennsylvania Office of Small Business Advocate	Equity cost of capital, cost allocation, rate design
R-2008-2075250	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil	April 2009	Pennsylvania Office of Small Business Advocate	Retainage rates
R-2009-2088076	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2009	Pennsylvania Office of Small Business Advocate	Gas procurement
R-2009-2083181	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2009	Pennsylvania Office of Small Business Advocate	Retainage rates, gas procurement

Note: Dates shown reflect submission date for direct testimony.

EXHIBIT IEc-2

SUPPORTING SCHEDULES

EXHIBIT IEc-2, Schedule 1

MAXIMUM ALLOWANCE UNDER 40-YEAR DEPRECIATION

[a]	Investment ($/kW)	969	<=== Increase over HQT	25.6%
[b]	Return	5.666%		
[c]	PV O&M	15.00%		
[d]	Yearly O&M (%)	0.96%		
[e]	Yearly Tax Rate	0.55%		
[f]	Rate/O&M Inflation	0.00%		

Year	Depreci-ation	Rate Base	Cost of Capital	Sub-Total	O&M	Taxes	Revenue Requirement	Revenue	Revenue Less O&M/Taxes
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Start		969							
2014	24	945	55	79	9	5	93.76	**74.65**	60.02
2015	24	921	54	78	9	5	92.25	74.65	60.15
2016	24	896	52	76	9	5	90.75	74.65	60.28
2017	24	872	51	75	9	5	89.24	74.65	60.42
2018	24	848	49	74	9	5	87.74	74.65	60.55
2019	24	824	48	72	9	5	86.23	74.65	60.68
2020	24	799	47	71	9	5	84.72	74.65	60.82
2021	24	775	45	70	9	4	83.22	74.65	60.95
2022	24	751	44	68	9	4	81.71	74.65	61.08
2023	24	727	43	67	9	4	80.21	74.65	61.22
2024	24	703	41	65	9	4	78.70	74.65	61.35
2025	24	678	40	64	9	4	77.19	74.65	61.48
2026	24	654	38	63	9	4	75.69	74.65	61.62
2027	24	630	37	61	9	4	74.18	74.65	61.75
2028	24	606	36	60	9	3	72.68	74.65	61.88
2029	24	581	34	59	9	3	71.17	74.65	62.02
2030	24	557	33	57	9	3	69.67	74.65	62.15
2031	24	533	32	56	9	3	68.16	74.65	62.28
2032	24	509	30	54	9	3	66.65	74.65	62.42
2033	24	484	29	53	9	3	65.15	74.65	62.55
2034	24	460	27	52	9	3	63.64	74.65	62.68
2035	24	436	26	50	9	3	62.14	74.65	62.82
2036	24	412	25	49	9	2	60.63	74.65	62.95
2037	24	388	23	48	9	2	59.13	74.65	63.08
2038	24	363	22	46	9	2	57.62	74.65	63.22
2039	24	339	21	45	9	2	56.11	74.65	63.35
2040	24	315	19	43	9	2	54.61	74.65	63.48
2041	24	291	18	42	9	2	53.10	74.65	63.62
2042	24	266	16	41	9	2	51.60	74.65	63.75
2043	24	242	15	39	9	1	50.09	74.65	63.88
2044	24	218	14	38	9	1	48.58	74.65	64.02
2045	24	194	12	37	9	1	47.08	74.65	64.15
2046	24	170	11	35	9	1	45.57	74.65	64.28
2047	24	145	10	34	9	1	44.07	74.65	64.42
2048	24	121	8	32	9	1	42.56	74.65	64.55
2049	24	97	7	31	9	1	41.06	74.65	64.68
2050	24	73	5	30	9	1	39.55	74.65	64.81
2051	24	48	4	28	9	0	38.04	74.65	64.95
2052	24	24	3	27	9	0	36.54	74.65	65.08
2053	24	0	1	26	9	0	35.03	74.65	65.21
Present Value				**969**	**146**	**57**	**1,172**	**1,172**	**969**
				O&M and Tax Percentages ==>	**15.1%**	**5.9%**			

Sources & Notes:

[a]: Derived iteratively from present value of column [10]

[b] - [e], [1] - [8]: Exhibit HQT-2, Document 1, Appendix B, adjusted for maximum investment

[f]: No inflation assumed in this calculation, see text.

[9]: HQT proposed tariff rate, $/kW, inflated at [f]

[10]: [9] - [6] - [7]

EXHIBIT IEc-2, Schedule 2

MAXIMUM ALLOWANCE UNDER 40-YEAR DEPRECIATION, LOAD PHASE-IN OVER 10 YEARS

[a]	Investment ($/kW)	593
[b]	Return	5.666%
[c]	PV O&M	15.00%
[d]	Yearly O&M (%)	0.96%
[e]	Yearly Tax Rate	0.55%
[f]	Rate/O&M Inflation	0.00%

Year	Depreci-ation	Rate Base	Cost of Capital	Sub-Total	O&M	Taxes	Revenue Requirement	Incremental Load	Revenue	Revenue Less O&M/Taxes
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[8a]	[9]	[10]
Start		593								
2014	15	579	34	48	6	3	57.42	0.10	**7.47**	-1.50
2015	15	564	33	48	6	3	56.50	0.15	11.20	2.32
2016	15	549	32	47	6	3	55.58	0.20	14.93	6.13
2017	15	534	31	46	6	3	54.66	0.25	18.66	9.95
2018	15	519	30	45	6	3	53.74	0.30	22.40	13.76
2019	15	504	29	44	6	3	52.81	0.35	26.13	17.57
2020	15	490	29	43	6	3	51.89	0.40	29.86	21.39
2021	15	475	28	43	6	3	50.97	0.45	33.59	25.20
2022	15	460	27	42	6	3	50.05	0.50	37.33	29.02
2023	15	445	26	41	6	3	49.12	0.55	41.06	32.83
2024	15	430	25	40	6	2	48.20	0.60	44.79	36.64
2025	15	415	24	39	6	2	47.28	0.65	48.52	40.46
2026	15	401	24	38	6	2	46.36	0.70	52.26	44.27
2027	15	386	23	38	6	2	45.44	0.75	55.99	48.09
2028	15	371	22	37	6	2	44.51	0.80	59.72	51.90
2029	15	356	21	36	6	2	43.59	0.85	63.45	55.72
2030	15	341	20	35	6	2	42.67	0.90	67.19	59.53
2031	15	326	19	34	6	2	41.75	0.95	70.92	63.34
2032	15	312	18	33	6	2	40.82	1.00	74.65	67.16
2033	15	297	18	32	6	2	39.90	1.00	74.65	67.24
2034	15	282	17	32	6	2	38.98	1.00	74.65	67.32
2035	15	267	16	31	6	2	38.06	1.00	74.65	67.40
2036	15	252	15	30	6	1	37.14	1.00	74.65	67.48
2037	15	237	14	29	6	1	36.21	1.00	74.65	67.57
2038	15	223	13	28	6	1	35.29	1.00	74.65	67.65
2039	15	208	13	27	6	1	34.37	1.00	74.65	67.73
2040	15	193	12	27	6	1	33.45	1.00	74.65	67.81
2041	15	178	11	26	6	1	32.52	1.00	74.65	67.89
2042	15	163	10	25	6	1	31.60	1.00	74.65	67.97
2043	15	148	9	24	6	1	30.68	1.00	74.65	68.05
2044	15	134	8	23	6	1	29.76	1.00	74.65	68.14
2045	15	119	8	22	6	1	28.83	1.00	74.65	68.22
2046	15	104	7	22	6	1	27.91	1.00	74.65	68.30
2047	15	89	6	21	6	1	26.99	1.00	74.65	68.38
2048	15	74	5	20	6	0	26.07	1.00	74.65	68.46
2049	15	59	4	19	6	0	25.15	1.00	74.65	68.54
2050	15	45	3	18	6	0	24.22	1.00	74.65	68.63
2051	15	30	3	17	6	0	23.30	1.00	74.65	68.71
2052	15	15	2	17	6	0	22.38	1.00	74.65	68.79
2053	15	0	1	16	6	0	21.46	1.00	74.65	68.87
Present Value				**593**	**89**	**35**	**718**		**718**	**593**
			O&M and Tax Percentages ==>		**15.1%**	**5.9%**				

Sources & Notes:

[a]: Derived iteratively from present value of column [10]

[b] - [e], [1] - [8]: Exhibit HQT-2, Document 1, Appendix B, adjusted for maximum investment

[f]: No inflation assumed in this calculation, see text.

[8a]: Assumed phase in of new load.

[9]: HQT proposed tariff rate, $/kW, inflated at [f], multiplied by [8a].

[10]: [9] - [6] - [7]

EXHIBIT IEc-2, SCHEDULE 3

HQT PROPOSED METHOD FOR NATIVE LOAD PROJECTS

ALTERNATIVE VERSION OF MS. CHANG'S TABLE 6, SCENARIO 2

		Scenario 2	Scenario 2A
	Step 1: Calculate Maximum Allowance Based on Allocation Units of the Resource-Related Projects		
[a]	Project Cost	100	50
[b]	Allocation Units (MW)	100	100
[c]	Maximum Allowance ($/kW)	598	598
[d]	Total Maximum Allowance for Resource-Related Project	59.8	59.8
	Step 2: Calculation Contribution for Resource-Related Projects		
[e]	Total Contribution*	40.2	0.0
[f]	Rolled-in Portion of Upgrade Costs	59.8	59.8
	Step 3: Calculation Contributons/Credits of Other Projects		
[g]	Substation A Project Cost	40	50
[h]	Substation B Project Cost	40	50
[i]	Substation C Project Cost	40	50
[j]	Substation D Project Cost	40	50
[k]	Substation E Project Cost	40	50
[l]	Total Substation Project Cost	200	250
[m]	Allocation Units (MW)	400	400
[n]	Maximum Allowance ($/kW)	598	598
[o]	Total Maximum Allowance	239.2	239.2
[p]	Total Contribution/(Credit)*	(39.2)	10.8
	Step 4: Measure Credits (if any) Against Remaining Contribution from Resource-Related Projects		
[q]	Are There Credits Left Over from Other Projects in Step 3?	Yes	No
	Step 5: Calculate Total Contribution		
[r]	Resource-Related Contribution from Step 1	40.2	0.0
[s]	Rolled-in Portion of Resource-Related Upgrade Cost Not Covered by Load-Based Credits	20.6	59.8
[t]	Total Resource Project Contribution	60.8	59.8
[u]	O&M (15%)	9.1	9.0
[v]	Total Contribution for Resource-Related Project	69.9	68.8
[w]	Total Contribution for Other Projects	0.0	12.4
[x]	**Total Contribution (Resource-Related & Other Projects)**	**69.9**	**81.2**

Sources and Notes

* Before application of 15% O&M.

Note that both the total project costs ($200 million) and the calculations are the same in each column, with the difference coming from the relative cost of resource-related and load-related projects.

See Exhibit HQT-2, Table 6 for assumptions and calculations, except that [e] may not be negative.

EXHIBIT IEc-2, SCHEDULE 4

HQT PROPOSED METHOD FOR NATIVE LOAD PROJECTS

ALTERNATIVE VERSION OF MS. CHANG'S TABLE 6, SCENARIO 3

		Scenario 3	Scenario 3A
	Step 1: Calculate Maximum Allowance Based on Allocation Units of the Resource-Related Projects		
[a]	Project Cost	100	50
[b]	Allocation Units (MW)	100	100
[c]	Maximum Allowance ($/kW)	598	598
[d]	Total Maximum Allowance for Resource-Related Project	59.8	59.8
	Step 2: Calculation Contribution for Resource-Related Projects		
[e]	Total Contribution*	40.2	0.0
[f]	Rolled-in Portion of Upgrade Costs	59.8	59.8
	Step 3: Calculation Contributons/Credits of Other Projects		
[g]	Substation A Project Cost	60	70
[h]	Substation B Project Cost	60	70
[i]	Substation C Project Cost	60	70
[j]	Substation D Project Cost	60	70
[k]	Substation E Project Cost	60	70
[l]	Total Substation Project Cost	300	350
[m]	Allocation Units (MW)	400	400
[n]	Maximum Allowance ($/kW)	598	598
[o]	Total Maximum Allowance	239.2	239.2
[p]	Total Contribution/(Credit)*	60.8	110.8
	Step 4: Measure Credits (if any) Against Remaining Contribution from Resource-Related Projects		
[q]	Are There Credits Left Over from Other Projects in Step 3?	No	No
	Step 5: Calculate Total Contribution		
[r]	Resource-Related Contribution from Step 1	40.2	0.0
[s]	Rolled-in Portion of Resource-Related Upgrade Cost Not Covered by Load-Based Credits	59.8	59.8
[t]	Total Resource Project Contribution	100.0	59.8
[u]	O&M (15%)	15.0	9.0
[v]	Total Contribution for Resource-Related Project	115.0	68.8
[w]	Total Contribution for Other Projects	69.9	127.4
[x]	**Total Contribution (Resource-Related & Other Projects)**	**184.9**	**196.2**

Sources and Notes

* Before application of 15% O&M.

Note that both the total project costs ($200 million) and the calculations are the same in each column, with the difference coming from the relative cost of resource-related and load-related projects.

See Exhibit HQT-2, Table 6 for assumptions and calculations, except that [e] may not be negative.